BHP Billiton Initial Submission to the Productivity Commission

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Review of National of Gas Code

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PART ONE

PRELIMINARIES AND INTRODUCTION

Chapter One

Introduction

1.1 Background

This is a submission by BHP Billiton ('BHPB') to the Productivity Commission's ('the Commission') review of the National Third Party Access Regime[1] ('the Regime') for Natural Gas Pipelines ('the Review'). As a business with long-standing and substantial interests in gas production, consumption and previous interests as a pipeline owner, BHPB is concerned to ensure that the regulatory regime for Australia's natural gas industry is as effective as possible. This submission represents the views of BHPB as a fuel supplier and user of gas transmission infrastructure, as a large consumer of gas, as a developer of pipeline infrastructure and as an experienced participant in regulatory processes.

As will be apparent from the views presented in this submission, BHPB considers that, while a number of specific changes to the Regime and its enforcement and administration would enhance its effectiveness, the current regulatory regime for gas is working effectively to contain the misuse of monopoly power and thus promote competition and growth in upstream and downstream markets, while supporting investment in new pipeline projects, where those projects are justified. That is, BHPB considers that, subject to the specific changes described in this submission, the current Regime provides an appropriate balance of the interests between the various participants, and one that is likely to maximise the growth potential for the Australian gas industry and hence its contribution to the growth of the national economy. BHPB has seen no evidence that the Regime has adversely impacted the national economy or the Australian gas industry, in fact we believe that it has had positive impact.

[1] The National Third Party Access Regime refers to the Gas Access Pipelines Law, the National Third party Access Code for Natural Gas Pipeline Systems and the Inter-Government Natural Gas Pipelines Access Agreement (7 November 1997).

BHPB involvement in Australia's gas industry

BHPB is a leading international diversified resources company. BHPB is a significant producer and consumer of gas nationwide and hence a significant user of monopoly infrastructure. Through its history BHPB's activities have also included the development of various pipelines, active participation in the development of the current regulatory framework and in the decision processes of various regulators under that framework.

Producer activities

BHPB Petroleum is one of the seven Customer Sector Groups (or businesses) of BHPB Limited. BHPB Petroleum started producing oil and gas in Australia in 1969, and remains the country's largest oil and gas production company.

In the 2002 financial year, BHPB Petroleum earned US$1,073 million (before interest and tax). In Australia, we produced 56 million barrels of oil and condensate, 169.8 billion cubic feet of natural gas (including liquefied natural gas) and 582,000 tonnes of liquefied petroleum gas from our Bass Strait, North West Shelf, Laminaria/Corallina and Griffin interests.

The Bass Strait Joint Venture is the largest asset in which BHP Billiton Petroleum has equity (50 per cent non-operator interest). It accounts for around 90 per cent of Victoria's natural gas requirements and 40 per cent of Australia's petroleum liquids production.

BHPB currently has an 8.33 to 16.67 per cent interest (depending on the production joint venture) in the North West Shelf Venture — Australia's largest resource development project, with investment totalling more than AUD$12 billion since 1984. The Joint Venture supplies natural gas to the domestic market in Western Australia as well as liquefied natural gas (LNG) to Japan and condensate, crude oil and liquefied petroleum gas (LPG) to international markets.

BHPB operates and has a 45 per cent interest in the Griffin Venture, which is a floating production, storage, and offloading vessel located offshore from Onslow on the north-west coast of Australia. This joint venture produces oil for domestic and export markets and sells associated gas into the West Australian domestic market.

Other production interests include a 90 per cent stake in the Minerva Joint Venture, which is a recent greenfield project to produce offshore gas from the Otway Basin (BHPB's share of capital expenditure is US$123 million), and a 50 per cent interest in a joint venture to develop coal seam methane from the Bowen Basin in Queensland, to be used to supply a Townsville power station. BHPB also has various shares in other static gas resources around Australia.

BHPB Petroleum also has an active exploration program for oil and gas in the offshore Gippsland, Carnarvon, Beagle and Browse basins.

Intermediate user activities

Even after disposing of our previous large interests in the steel industry that are major consumers of gas in the NSW, Victorian and South Australian markets, BHPB remains a major customer of natural gas through our operations in Western Australia and Queensland. BHPB's current gas consumption includes:

- Hot Briquetted Iron (HBI) Plant at Port Headland, WA. This plant consumes approximately 40PJ/pa to produce HBI;
- The Worsley integrated alumina refinery/bauxite mine, WA, (86 per cent owned by BHPB) consumes approximately 20PJ/pa to produce alumina and generate electricity via cogeneration ;
- Supply of approximately 5PJ/pa to power stations in Port Hedland and Mt Newman; and
- The Cannington mine in Queensland, producing silver, lead and zinc, and associated processing plant, consumes approximately 2.5PJ/pa. .

In addition, BHPB owns the QNI nickel smelter located in Townsville, which can convert to natural gas once natural gas supply is extended to the area and has a potential load of up to 16PJ/pa.

It goes without saying that, with such large investments in downstream, gas-intensive assets, BHPB has a strong interest in ensuring a continued access to gas over the long term, at a reasonable price, but also with continued reliability of supply.

Involvement in pipelines

Throughout its history, BHPB has been involved in a number of pipeline developments including:

- An original developer in the Eastern Gas Pipeline (EGP) holding a 50 per cent share with Westcoast Energy of Canada. BHPB (along with Westcoast) sold its EGP development rights to Duke Energy International, and – as half owner of the Bass Strait Joint Venture – signed a foundation transportation contract for the subsequent use of the pipeline.
- A foundation partner in the Goldfields Gas Transmission (GGT) Pipeline Joint Venture, holding a 12.5 per cent share, which was sold in December 1998/99 to Duke Energy International.

- A developer and foundation owner of the Pilbara Pipeline (Karratha to Port Headland). This pipeline was sold to Epic Energy in 1998 with an underpinning gas transportation contract with BHPB.
- Tasmania Gas Pipeline — The Bass Strait Joint Venture has signed a long term gas supply agreement with Duke Energy International to supply the underpinning volumes needed for this pipeline development.

BHPB also assisted in the development of the SEA Gas Pipeline by signing a long-term gas supply agreement (with International Power) for supply from BHPB's Minerva Gas Field. International Power intend to transport this gas via their foundation reservation in the SEA Gas Pipeline to their Pelican Point Power station in South Australia.

Involvement in regulatory processes

Given is broad array of interests in the gas industry, BHPB was an active participant in the development of the existing Regime. Our involvement with regulatory processes and development continues in two important ways: BHPB takes an active role in access arrangement review processes and has made submissions to regulatory reviews conducted by ACCC, ESC in Victoria, IPART in NSW, SAIPAR in SA and ICRC in the ACT. In addition, BHPB is the Australian Petroleum Production and Exploration Association (APPEA) representative on the National Gas Pipelines Advisory Committee (NGPAC) and thus is involved in work to achieve on-going refinements in the operation of the Code. BHPB has made recent substantiative submissions to:

- NGPAC issues papers that have been circulated for public comment;
- the NCC on applications for the revocation of pipelines;
- the Productivity Commission on the ‘Part IIIA of the Trade Practices Act’ (‘Part IIIA Review’); and
- the Independent Review of Energy Market Directions (‘Parer Review’).

1.2 The Commission’s Task

The aim of the Commission’s Review is to examine the extent to which current gas access arrangements:

- balance the interests of relevant parties;
- provide a framework that enables efficient investment in new pipeline and network infrastructure; and
- can assist in facilitating a competitive market for natural gas.

The Commission has been requested to:

- analyse and, as far as reasonably practical, assess the benefits, costs and effects of the Gas Access Regime, including its effects on investment in the sector and in upstream and downstream markets;
- identify any necessary improvements to the Gas Access Regime, its objectives, application, and in particular the Code, to ensure uniform third party access arrangements exist on a consistent, national basis;
- consider the appropriate consistency between the Gas Access Regime, the National Access Regime, and other access regimes; and
- identify and investigate the appropriateness of including in the Code minimum requirements by which pipeline owners and/or network owners could provide access.

1.3 Overview and Structure of the Submission

The submission is presented in four parts.

This part, *part one* presents this introductory chapter.

BHPB is concerned that much of the debate in the two recent reviews relevant to gas access regulation in Australia — the Commission's review of Part IIIA Review and the Parer Review — formed views and made recommendation on the costs and benefits of the relevant access regimes largely on the basis of theoretical possibilities rather than on objective and reliable empirical evidence. However, given the obvious strong commercial interests of the various participants in the debate about the Regime, BHPB considers it essential that the Commission base its analysis of the appropriateness of the Regime — as well as the performance of regulators in applying that Regime — on an assessment of objective facts of what has happened under the Regime, rather than on the unsupported statements of participants.

Part two of this submission provides an analysis of the outcomes that have occurred over the period of the Regime that BHPB considers relevant to an assessment of how well the Regime promotes the efficient growth of the gas market, and hence its contribution to the growth of the national economy.

Chapter 2 discusses the different elements of the Regime, as well as the other components of the comprehensive set of reforms to the national gas industry that governments have implemented. This includes a description of the model for reform that all Australian governments agreed to implement, and thus the outcomes for each of the sectors in the gas industry that were sought. Lastly, this chapter includes a discussion of the development of the Regime, and in particular, the time lines for the development of the Regime. Importantly, it is noted that the introduction of a

mandated access regime for gas pipelines was foreshadowed as early as 1991 — and a firm commitment by all governments as early as 1994. It is also noted that the current Regime was developed with extensive direct involvement of all parts of the industry, and that the whole package was supported by all parts of the industry at the time of its introduction. In their criticisms of the Regime, the relevant pipeline industry associations have pointed to a number of specific projects that they consider to have been adversely affected by the Regime. This criticism is addressed against the objective evidence considered in the chapters three and four.

Chapter 3 assesses the actual outcomes for each of the main sectors of the Australian gas industry over the period during which the Regime was foreshadowed and has been in operation, and compares them to the outcomes that were expected by governments when agreeing to implement the natural gas industry reforms. In particular, the chapter analyses against objective evidence the outcomes that have been achieved in each of the sectors of the industry, that is, the transportation sector (transmission and distribution), the upstream sector (production) and the downstream sector (consumption). The evidence presented in the chapter provides strong support for the view that, far from being stifled in its development, all elements of the natural gas industry have developed over the period since the Regime's inception — and there is room for confidence that many of the outcomes envisaged by governments when the reforms to the gas industry were agreed will be achieved.

Chapter 4 discusses in detail the full background to the specific projects that have been claimed to have been 'chilled' by the Regime, in particular, two high profile pipeline projects, and a number of gas distribution projects to regional Victoria. The inevitable conclusion from the consideration of the wider context is that, far from being evidence of failings in the current Regime or its administration, the deferral of these projects may be more indicative of its success. This chapter also discusses more broadly the issues associated with new investment under the Regime, including the flexibility inherent in the Regime, and the attempts by Regulators to accommodate the legitimate concerns of investors.

Part three of this submission presents in more detail BHPB's views on the appropriateness of the specific features current Regime, including its views on components of the current Regime that are critical to the Regime's success, and its views on where changes to the current Regime should be made.

Chapter 5 discusses two of the features of the current Regime that BHPB consider are critical to the Regime's success, which are its focus on cost based pricing, and its inclusion of strong ring fencing requirements. That said, BHPB accepts that some changes to the current pricing principles may be appropriate to permit regulators to explore more robust means of setting the 'X factor' in price caps. BHPB also considers that the effective introduction of competition into the supply

of gas to final customers may require additional measures to the current ring fencing requirements — or at least proper enforcement of the current requirements.

Chapter 6 presents BHPB's views on a number of its specific concerns with the current Regime, and on the changes to the Regime that it considers appropriate. The specific issues discussed are:

- the objectives for access pricing;
- the inappropriateness of the asymmetry of the rights that different parties have to appeal a regulator's decision on an access arrangement;
- the powers of regulators to obtain information from service providers;
- the identity of the regulator under the Code and the benefits of having a single national regulator; and
- the arrangements for the ongoing administration of the Code — in particular, the role of industry in the Code change arrangements.

BHPB has also commissioned The Allen Consulting Group to produce an independent report on a number of the more technical issues relevant to the Commission's review of the Regime. As well as restating the rationale for regulation of the transportation components of the gas industry, the Group's report considers four specific issues, which are:

- the rationale for the current form of regulation applied when approving reference tariffs, including the role of incentive regulation and the relevance of the comments about the 'building block approach', and its views on the strengths of the current pricing principles, and on where changes would be appropriate;
- whether there is a strong *a priori* reason for considering that access prices should err in favour of the regulated business;
- the potential real-world applicability of the concerns expressed about encouraging new investment under the Regime — in particular, the concern about 'truncation' of returns; and the empirical evidence on the whether there is evidence that regulators have actually been 'overly ambitious' at removing the monopoly rents earned by the transportation elements focussing on how the values placed upon the regulated businesses by the market — either in the context of trade sales or implied by share prices — compare to their regulatory values.

BHPB supports the conclusions reached by The Allen Consulting Group, and commends them to the Commission's consideration.

Chapter Two

The Gas Access Regime – History, Intended Outcomes and Framework for Assessment

2.1 Why regulate gas pipelines?

It is useful to revisit the primary reason that governments, regulators and industry all agreed on the need for a regulatory regime for Australia's gas pipeline industry in the first instance. Downstream gas pipeline infrastructure is a natural monopoly: the most cost effective means of transporting gas is to have a single pipeline from the source of supply to consumers. A consequence of the having a single pipeline is that the pipeline owner/operator has substantial market power. If unchecked by some form of government action, any natural monopoly has both the incentive and the opportunity to a set price (or quantity) to maximise its profit. While this is good for the natural monopoly, it results in broader economic inefficiencies.

The economic inefficiency from natural monopoly behaviour arises because the price that maximises the natural monopolist's profit is higher than the competitive market price. Monopoly pricing can have a substantial effect on investment in upstream and downstream industries, stifling growth and costing jobs. It also creates prices that are unfair to residential customers. The location of the monopoly pipeline in the middle of the gas supply chain means that the monopoly price can also dampen incentives and opportunities for competition in upstream and downstream markets to protect affiliates.

The nature of these market failures in the gas industry imply that governments need to regulate both access to pipelines, as well as the price that can be charged by pipeline owners for this access. This requires a robust regulatory regime as access denials and monopoly pricing can be very hard to distinguish where there are vertical linkages between the owner of the monopoly infrastructure and a participant in the downstream market — a scenario which is prevalent in Australia's gas industry today. The current regulatory regime for the gas industry — which

comprises both access and pricing regulation — is therefore the most appropriate form of regulation for the industry as it currently stands.

While it is an obvious point, it is useful to recall that the natural monopoly characteristic of gas pipelines is not subject to change — it is caused by the technology. Thus, there will always be a role for government actions in the pipeline industry to promote economic efficiency by countering the market power inherent in the natural monopoly gas pipelines.

These issues are discussed in more detail in chapter 2 of The Allen Consulting Group's submission to the Review.

2.2 Evolution of the Gas Access Regime

Before commencing an analysis of the impact of the current Gas Access Regime on outcomes for the industry it is important to establish two things:

- firstly, the original objectives for reform — this allows us to make an assessment as to whether or not the experience of the Regime in practice has indeed served to promote these objectives; and
- second, a clear starting point for the analysis — in this regard, it is our view that while the package of legislation that included the Gas Code was only agreed to by Heads of Government in 1997 — and then put into legislation some time later — the essential features of the Regime had been foreshadowed with increasing clarity years earlier.

Impetus for reform

The impetus for the reform of Australia's gas industry began in the early 1990s. In 1991, the Industry Commission (IC) released a report entitled *Energy Generation and Distribution* which concluded that the gas industry in Australia had not been performing to its full potential. In particular, the IC found that because of excess capacity and gross overstaffing, gas prices failed to accurately reflect the cost of gas supply. The IC concluded that reform of the industry to correct inefficiencies could yield substantial benefits to the economy in the order of nearly $150 million annually.[2]

The IC attributed much of the inefficiency in the gas industry to an industry structure dominated by government-owned, vertically integrated enterprises in each jurisdiction, with little competition and trade in gas across State borders (with the exception of Moomba gas going into NSW). Consequently the report recommended a range of changes to institutional and regulatory arrangements in the gas sector including the separation of the ownership of distribution and transmission functions, and requiring all transmission and distribution pipeline owners to provide open access to their pipes.

The IC report was followed in February 1994 by the decision of the Council of Australian Governments (COAG)[3] to pursue a broad national agenda for microeconomic reform, as articulated in the Hilmer Report. Hilmer's reforms sought to encourage competition in the activities of government-owned enterprises and, in particular, competitive neutrality between public and private sector

[2] Industry Commission (1991), *Energy Generation and Distribution*.

[3] Information on COAG decisions are taken from the Department of Prime Minister and Cabinet's website at www.dpmc.gov.au.

industries. At the same time, COAG made a commitment to pursue specific reforms aimed at achieving free and fair trade in natural gas, including the removal of legislative and regulatory barriers to trade in gas, and a uniform national framework for third party access to all gas transmission pipelines.[4] In line with the IC's recommendations, the underlying objectives of this commitment were:

- to remove policy and regulatory impediments to retail competition in the natural gas sector;
- to remove a number of restrictions on interstate trade; and
- to encourage the development of a nationally integrated and competitive natural has market by establishing a national regulatory framework for third party access to natural gas pipelines and facilitating the interconnection of pipeline systems.[5]

The Gas Reform Task Force

COAG's decision to pursue 'free and fair trade' in gas provided the momentum for the establishment of the Gas Reform Task Force in April 1995. The Task Force had a mandate to progress reform and eventually to draft an Access Code.

The Task Force used the following five key objectives as the framework for the Code's development:

- to provide an open and transparent process for establishing third party access to natural gas pipelines in order to reduce uncertainty for market participants;
- to facilitate the efficient development and operation of a national natural gas market and to safeguard against abuse of monopoly power;
- to promote a competitive market for gas, in which customers are able to choose the supplier (producer, retailer and trader) they want to trade with;
- to provide a right of access to transmission and distribution networks on fair and reasonable terms and conditions, with a right for all people and parties to a binding dispute-resolution mechanism; and
- to encourage the development of an integrated pipeline network.[6]

In June 1996, COAG agreed to the Task Force's proposed form for the Access Code and decided that the Code should apply to distribution systems as well as transmission pipelines. The Gas Reform Task Force subsequently developed and released the draft 'National Third Party Access Code for Natural Gas Pipeline

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[4] Council of Australian Governments, Communiqué, Hobart, February 1994.

[5] Gas Reform Implementation Group (1997), *Policy Information Paper: National Access Regime for the Natural gas Industry*.

[6] Gas Reform Implementation Group (1997), *op-cit*.

Systems' in July 1996. This draft was then reviewed in light of comments from a series of public seminars held around Australia, and submissions were taken from interested stakeholders. Following this extensive stakeholder consultation, the draft Access Code was revised and on 7 November 1997, Heads of Government signed the final National Gas Pipeline Access Agreement and agreed to implement the National Third Party Access Code for Natural Pipeline Systems. As well as the Code itself, the national access regime agreed by COAG in 1997 consisted of:

- *legislation to give effect to the Code* — each jurisdiction, led by South Australia, passed legislation to give effect to the national access Code; and
- *an intergovernmental agreement* — this was signed by each jurisdiction setting out jurisdictions' obligations in relation to giving legislative effect to the Code within a specific time frame and other actions to implement and maintain the integrity of the Code.

Table 2.1 shows key milestones to date in the evolution of the current regulatory regime for the gas industry in Australia.

Objectives of the regime

It was hoped that the implementation of this access regime would bring many benefits to the broader economy. COAG said on signing the Natural Gas Pipeline Access Agreement in 1997 that the reforms aimed to:

- foster greater competition in the delivery of gas leading to lower prices, greater choice for consumers and environmental benefits;
- provide the certainty required to encourage additional investment in resource exploration and development, and in pipeline infrastructure leading to an integrated gas pipeline network;
- increase the competitiveness of gas-consuming industries, thereby stimulating investment and generating jobs.

Specifically, COAG said the new arrangements would facilitate the development of new pipelines — such as the Eastern gas Pipeline — and in doing so promote competition between the Cooper Basin and Bass Strait in the eastern Australian gas market.

This submission will show that this regime has been successful in meeting COAG's original goals for the reform process, in particular in relation to:

- the transfer of gas assets to the private sector;
- a substantial increase in competition at all levels in the industry, resulting in better price and quality outcomes for gas consumers; and

- the promotion of investment in the gas industry, in particular investment in new pipeline infrastructure linking various State markets.

These issues are discussed in more detail in chapters 3 and 4.

Table 2.1 Milestones in the Reform Process

Year	Event
1991	*May*: The Industry Commission releases its report on its review of energy generation and distribution in Australia. The Commission recommends significant changes to structure of natural gas and electricity supply industries, including separation of the ownership of distribution and transmission functions, and requiring all transmission and distribution pipeline owners to provide open access to their pipes. The Commission also recommends the Trade Practices Commission (now the ACCC) to oversee the development of operating guidelines concerning network access and pricing issues.
1992	*December*: The Council of Australian Governments (COAG) asks the Australian and New Zealand Minerals and Energy Council (ANZMEC) to prepare a report examining barriers to trade in natural gas that inhibit the development of the gas industry and discourage exploration and commercial development of gas markets and related infrastructure.
1993	*June*: COAG receives ANZMEC's report. The report recognises governmental impedients to free and fair trade in natural gas. Heads of Government agrees to co-operate in the development of policies and arrangements to remove impediments to free and fair trade in natural gas. COAG establishes a Working Group for Gas Reform and calls for a further report to examine a pro-competitive framework for the natural gas industry.
1994	*February*: COAG receives a report from the (Government-officials) Working Group on Gas Reform entitled *Progress Towards A Pro-Competitive Framework for the Natural Gas Industry, Within and Between Jurisdictions*. COAG commits to a broad set of reforms to the natural gas industry, including the introduction of a regime for third-party access to pipelines. It sets a target date for the introduction of these reforms of 1 July 1996.
1995	*June*: The Intergovernmental Gas Reform Task Force established to develop national arrangements for third party access to natural gas pipelines and to prepare a "Scoping Study" on gas reform . The Taskforce was comprised of officials from all Australian governments, representatives from all sectors of the gas industry (upstream and pipeline and gas users) and an independent Chair. The Task Force subsequently proposes that the uniform national framework take the form of a Code.
1996	*June*: COAG agrees that a national pipeline access uniform framework will take the form of a Code. The Code will be supported by legislation in each jurisdiction to deal with the implementation and maintenance of the Code.
	July: The Draft Access Code is released for a two month stakeholder consultation period.
	August: Gas Contestability introduced for large users in New South Wales (>500 TJ)
	December: Gas Reform Implementation Group established to finalise outstanding issues on the Code and to develop the Inter-Governmental Access Agreement.
1997	*January:* Gas Contestability introduced for large users in Western Australia (>500 TJ).
	November: Heads of Government sign the National Gas Pipeline Access Agreement on 7 November 1997 and agree to implement the National Third Party Access Code for Natural Pipeline Systems.
1998	*April:* Gas Contestability introduced for large users in South Australia (>100 TJ).
	July: South Australia introduces lead legislation establishing the third party access regime for gas pipelines which gives effect to the *National Third Party Access Code for Natural Gas Pipeline Systems*.
1999	*October*: Gas contestability introduced to large users in Victoria (>500TJ)
2000	*December*: Gas contestability introduced in Queensland for large users (>100TJ)
2002	*January*: Full retail contestability introduced in New South Wales and ACT.
	October: Full retail contestability introduced in Victoria.

Sources: National Competition Council (1998), *Compendium of National Competition Policy Agreements*. National Competition Council (2002) Submission to the to the COAG Energy Market Review. The Code Registrar website; Australian Gas Association (2001*) Gas Statistics Australia 2001;* Department of Industry Science and Resources *Australian Energy News* , December 6, 1996.

Industry support for the Code

It is worth noting that the methodology used by the Gas Reform Task Force to develop the Code ensured that industry representatives had substantial input into the process. The Task Force used a series of working groups — comprised of government, industry (including the Australian Pipeline Industry Association (APIA), the Australian Gas Association (AGA) and the Australian Petroleum Production and Exploration Association (APPEA)) and user representatives — to distil and resolve the relevant issues. Broad agreement was reached within these working groups before the draft and final Access Code documents were finalised. Statements from industry around the time of the Code's finalisation indicate the high level of industry support for the introduction of the Code:

> The Australian Gas Association, which represents producers and users nationally, and the Australian Petroleum Production and Exploration Association, which represents the petroleum industry, both welcomed passage of the legislation [in relation to access to gas pipelines]…Peter Dalkin, chief executive of the AGA, said its passage removes uncertainties about regulations that could have been holding back investment. He also believes it will usher in a new era of lower gas prices, reflecting increased competition among all sectors of the industry.
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> 'Australia nearer national gas market as senate passes law', *Dow Jones Australia and New Zealand Report*, 9 July, 1998.

> Mr James [Chief Executive, Epic Energy Pty Ltd] said Epic, which represents 16 per cent of Australia's gas transmission business, was optimistic that the regulatory process could benefit the pipeline industry and its customers…'Australia's gas industry will achieve growth unparalleled in the region, combined with the gas-on-gas competition that is necessary to reduce consumer prices and stimulate investment and growth.'
>
> 'National gas flow key to turn investment tap', *The Australian*, 17 February 1997

> The Australian Gas Association has called for the immediate implementation of an access code. It is asserted that such a code will generate competition within the country's gas supply sector.
>
> 'Aust gas market is "dead, ossified"', *Daily Commercial News*, 22 October 1997.

> About $6 billion of gas infrastructure projects would be at risk if pipeline access arrangements were not approved by the Council of Australian Governments in November, Australian Gas Association chairman Greg Harvey said yesterday…With gas demand and infrastructure development set to charge ahead, the basic national framework for gas industry reform and pipeline access must be implemented urgently,
>
> '$6bn gas project count on access code', The Australian, 21 October 1997.

These statements from industry highlight that the Gas Code was not developed by bureaucrats and then imposed on the industry, but that industry participants were intimately involved in its development through the extensive network of working groups.

Starting point for our analysis

From the discussion above, it follows the likelihood of some form of mandated access regime for gas transmission and distribution systems as part of a broader suite of reforms to the natural gas industry was foreshadowed as early as 1991. A commitment from all governments to examine further these reforms made in 1992, and the commitment to adopt a package of reforms – including a mandated access regime – announced in early 1994. Work on the drafting of the Gas Code – which included input from many of the key industry participants commenced in 1995, and a draft of the Code – which was very similar to the product finally approved – was circulated for wider public comment in mid 1996. Moreover, that year also saw the first decision by an independent regulator under a gas access code.

Further, before the inception of the National Code, a number of States progressed towards their own state-based third party access initiatives. Western Australia developed regulatory arrangements for third party access to the Dampier to Bunbury Natural Gas pipeline and the Goldfields gas pipeline around 1996. New South Wales also established a third party access regime for transmission pipelines in August 1996 with an indicated intention of adopting the National Code when it has been agreed by CoAG.[7] Correspondingly, News South Wales and Western Australia introduced gas contestability for gas large users in 1996.

As indicated in Table 2.2, a draft decision of an access arrangement for AGL's distribution network was finalised in September 1996 – one year before the Code was introduced. The arrangements were based on the *Gas Supply Act 1996* (NSW) and the *Third Party Access Code for Natural Gas Distribution Networks in NSW*, as gazetted on August 30th 1996.

[7] Department of Industry Science and Resources *Australian Energy News* "Developing a National Energy Market", December 6, 1996.

Table 2.2 Gas Transmission and Distribution Final Decisions On Access Arrangements

Access Arrangement	Draft Decision	Final Decision	Regulator
AGL Gas Networks	Sept 1996.	Nov 1996.	IPART
Victorian transmission systems.	28/5/1998	6/10/1998	ACCC
Victorian distribution systems.	3/6/1998	6/10/1998	ORG
Great Southern Networks (Wagga Wagga)	29/9/1998	8/3/1999	IPART
Access review of AGL Gas Networks	28/10/1999	21/7/2000	IPART
Albury Gas Company	2/7/1999	31/12/1999	IPART
Central West Pipeline	10/9/1999	30/6/2000	ACCC
Mid West and South West distribution systems (Alinta).	14/3/2000	30/6/2000	OffGAR
Tubridgi Pipeline System	7/8/2000	19/10/2001	OffGAR
Moomba to Adelaide	16/8/2000	14/9/2001	ACCC
South Australian distribution system	13/4/2000	21/12/2001	SAIPAR
Queensland distribution systems	23/3/2001	3/10/2001	QCA
Wallumbilla to Rockhampton	11/4/2001	1/8/2001	ACCC
Amadeus to Darwin	2/5/2001	4/12/2002	ACCC
Ballera to Wallumbilla	13/6/2001	28/11/2001	ACCC
Dampier to Bunbury Natural Gas Pipeline	21/6/2001	23/5/2003	OffGAR
Roma to Brisbane and Carpentaria Gas Pipelines	15/8/2001	16/1/2002	ACCC

Source: Regulator websites. Excludes pipelines with coverage revoked.

We consider it reasonable to assume that industry participants would have factored in to their decisions the likelihood of a mandated access regime as early as 1991, and considered such a regime a high probability by 1994, and then had substantial certainty about the final shape of the regime by mid 1996.

2.3 Other Reforms and Privatisation

It is important to note that many Australian governments have made other changes to their involvement in the gas industry on the assumption that the Gas Code would provide a robust tool for controlling the market power of the natural monopoly elements.

Prior to the introduction of the Gas Code, the prices for delivered gas (at least to small consumers) were regulated in some form in most Australian jurisdictions, albeit in some cases indirectly through their ownership of utilities, and also often not transparently by a decision maker who was independent of the government's political interests of the day. However, as part of the package of reforms that have been introduced to the gas industry, many of those previous regulatory price controls have now been removed, with the remaining controls on final prices now

largely limited to small customers and intended only to apply for a transitional period prior to the establishment of effective competition amongst retailers.[8]

In addition, a substantial program of privatisation of the formerly government owned utility infrastructure has been undertaken in the period since their commitment to mandated access regulation, as set out in Table 2.3.

Table 2.3 Privatisation of Government Gas Assets

Year	Asset
1994	*June*: Sale of the Moomba to Sydney Pipeline (Transmission Pipeline Authority) to EAPL (AGL 51%).
1995	*July*: Sale of transmission pipelines in South Australia (Pipeline Authority of SA) to Epic Energy
1996	*June*: Sale of Queensland State Gas Pipeline to PGE.
1998	*March*: Sale of Dampier to Bunbury Natural Gas Pipeline to Epic Energy
1999	*June*: Sale of high pressure transmission pipelines (Transmission Pipelines Australia) in Victoria to GPU GasNet. Sale of Victorian distribution networks (Multinet, Westar, Stratus) to United, TXU and Envestra.
2000	*June*: Privatisation of AlintaGas via public float.

Source: Merrill Lynch.

It is reasonable to expect that many of these governments would have taken great comfort from the existence of the Gas Code – and its system of cost-based regulation by an independent regulator – when deciding whether the privatisation of the monopoly infrastructure for such an essential service was in the public interest. Indeed, the Victorian Government expressed its views as to the outcomes of regulation under the Gas Code as follows:[9]

> The monopoly elements of the gas industry, transmission and distribution, will be regulated by the ACCC and the ORG respectively. The regulation of these elements will ensure that consumers pay the lowest sustainable price possible for the transportation of gas.

The Victorian Government made it clear that it saw regulation under the Gas Code as delivering this outcome.10

> The Government is committed to the national gas reform framework agreed to by the Council of Australian Governments ('CoAG') in 1994. The framework sets out access rights to natural gas supply networks and promotes free and fair trade in natural gas between jurisdictions.

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[8] The transitional role of retial price controls applies only in jurisdictions that have committed to introduce full retail contestability.

[9] Department of Treasury and Finance, Victoria's Gas Industry: Implementing a Competitive Structure, Information Paper No.3, April 1998, p.10.

[10] Department of Treasury and Finance, Victoria's Gas Industry: Implementing a Competitive Structure, Information Paper No.3, April 1998, p.18.

The Commission's assessment of the appropriateness of the current regime – a well as the benefits created – needs to take account of the removals of other protections for customers that have accompanied the Regime, as well as the other reforms – such as privatisation of formerly government-owned utilities – that has only been possible as a consequence of a regulatory regime such as that under the Gas Code.

2.4 The Need to Consider Objective Evidence

A repeated claim of pipeline owners and their representatives is that the regulatory framework for gas pipelines in Australia has had an adverse effect on new investment in the industry[11]. The two claims have been that regulators have set prices that are too low – focussing too heavily achieving short term price benefits for consumers, at the expense of encouraging appropriate levels of long term investment, and secondly that regulation has created additional uncertainty for pipeline owners. The effects of the Regime – according to these arguments – are that:

- a sub-optimal development of the gas network is being encouraged – with major projects being deferred as a consequence of regulation; and
- a negative investment climate generally, with a reduction in the market values of some of the pipeline companies as a result of regulation, the likely collapse of one major pipeline company and the withdrawal of Australian and foreign capital from the industry.

For example, APIA commented that:

> …for much of 2002, the pipeline industry remained under siege in its goal of development towards a truly national gas market and creation of a genuinely competitive producer sector…our investors remain disenchanted and ever more wary, and little real progress is made towards the expansion of Australia's gas infrastructure towards a national grid.
>
> Government must build on infrastructure 'glimmer of hope', *APIA Media Release*, APIA President, Jim McDonald.

Similarly, AGA expressed its views as follows:

Grant King, chairman of the Australian Gas Association and managing director of Boral Energy, warns that appreciation of industry asset values could result in over-capitalisation and falling returns. Deregulation of the industry was expected to encourage new investment, but resulted in "far more prescriptive and onerous regulatory regimes than we ever envisaged". He added that regulations on owners of

[11] These arguments are taken from the APIA and AGA submissions to the COAG Energy Markets Review (2003).

natural gas transmission and distribution infrastructure discouraged investment because of the difficulty in convincing regulators of the returns necessary to fund investment in, and replacement of, infrastructure… 'We find the uncertainty of current regulatory outcomes to be discouraging in the extreme.'

'Gas industry warned', *Petroleum Economist*, 23 December 1998

In what has become the industry's favourite pastime, Mr King…took a swipe at the present 'onerous' gas regulations and claimed the conflicting role of governments had resulted in 'significant unpredictability and inconsistency' within the industry… 'In terms of economic regulation, governments behave differently as asset owners as distinct from regulators,' Mr King said…'When they are selling assets they own, they argue for higher returns and clear regulatory arrangements…When [they are] owners but not sellers, they want no express regulatory arrangements other than the ability to control pricing and infrastructure development. When they're regulators and not owners they argue for lower returns.

'Policy hot air a drag on gas - Boral chief', *The Australian*, 17 November 1998

Mr King was also quoted as saying in November 1998:

It is ironic that four years ago we looked forward to an age of light-handed regulation...In fact, our principal members, the owners of natural gas transmission and distribution infrastructure, find themselves burdened with prescriptive re-regulation. These arrangements are complex and time consuming in their implementation and discouraging to investment.

'Australian gas chief calls for uniform energy policy', *Asia Pulse*, 16 November, 1998

Importantly, the AGA considered that the adverse impact of the Gas Code extended beyond the 'greenfields' projects to investment in the regulated activities generally.

The Commission itself has accepted that there is a *potential* for regulation to have a 'chilling' effect on investment.[12] The Parer report noted also noted the views of the pipeline industry – as well as those to the contrary by customers and the upstream – but did not form a view as to which view was correct.

It goes without saying that the pipeline industry has a very strong commercial incentive to overstate the adverse effects of the Gas Code — a Code which, as noted above, it helped to develop. Accordingly, it is essential that the Commission base its assessment on the objective evidence that exists as to the development of the industry over the period for which the Regime would have had an effect, rather than on the industry's unsupported (and, we consider, unsupportable) rhetoric. It is also

[12] Productivity Commission, 2001, Review of the National Access Regime, Report No.17, AusInfo, page XIX

imperative that the Commission consider the objective evidence of the Gas Code's effect on the whole of the industry — in particular, on the benefits that have flowed through to downstream users, and industry, and subsequently to the growth of the Australian economy.

Moreover, when assessing arguments like the effect of regulation on the values of regulated businesses, it is imperative that the Commission look past the obvious measures at more relevant indicators of the effects of regulation. As will be noted below, while a number of investors have paid substantial sums of money for regulated assets in Australia, a question remains as to the prudence of the prices paid. As BHPB knows all too well, firms that operate in competitive markets cannot complain to the regulator when they make bad decisions – this is a privilege that exists only for regulated firms.

The following two chapters present objective evidence on the effects of the Regime on the gas industry – and, in particular, on the extent to which there should be confidence that the objectives of the gas reforms will be met – for the Commission's consideration. Chapter 3 presents evidence on the actual outcomes for the three sectors of the gas industry since the early 1990s, that is, the pipeline (transportation) sector, upstream and downstream. Chapter 4 then addresses some of the specific adverse outcomes that the pipeline industry associations have raised. This includes the claim that specific transmission projects and distribution projects have been deferred, as well as the more general claim that the Code fails to provide investors with adequate flexibility.

Chapter Three

The gas industry under the Code

Key Points

- Investment in new *pipeline infrastructure* has been strong and increasing during the period of the current regulatory regime:
  - Over 9,000 kilometres of new transmission pipeline were laid between 1989 and 2002 (an increase of 113 per cent). Over 23,000 kilometres (an increase of nearly 45 per cent) of new distribution pipeline were laid over the same period.
  - Since 1990/91, around $7 billion has been invested in gas pipeline assets — $3.7 billion in transmission and $3.3 billion in distribution.
  - There has been a substantial change in the ownership of gas pipeline assets since 1990. Over $17 billion in transactions involving these assets have been undertaken since 1994.
- Activity and diversity have also increased substantially in the *upstream gas sector* since the inception of the Code:
  - Between 1990 and 2001, the volume of total gas reserves (commercial and non-commercial) increased by 102 per cent.
  - Exploration — which is an important leading indicator of future activity in the industry — has also grown substantially, while a number of new supply sources have come on line from both greenfields and existing developments.
  - The gas production sector has developed to a point where there are multiple sellers in both the East Coast and West Australian markets. As a result, sustainable long-term supply competition now exists.
- *The downstream sector* has developed in line with growth in investment and upstream activity during the period of the Code, although scope remains for increased competition at the retail level:
  - Gas is now a major source of energy in Australia — as a proportion of total energy fuels used, natural gas increased from 16.6 per cent in 1991 to 19.7 per cent in 2001.
  - Natural gas consumption has increased by nearly 50 per cent since 1990. The largest increases in gas consumption as a proportion of total sectoral energy consumption were from the mining (over 50 per cent) and manufacturing (over 30 per cent) sectors.
  - More households now have access to natural gas — growth in household natural gas connectivity was most prominent in the ACT, Western Australia, Victoria and South Australia where connectivity is above 50 per cent.
  - On average, the real household price of natural gas has increased by 7 per cent since 1990. However, Melbourne, Brisbane and Perth have experienced

a decline in the real price of household gas.

– Because of the wide range of potentially countervailing factors impacting on gas prices, it is difficult to distil the Regime's direct impact on prices to date. Nevertheless, it is certain that the regulatory regime will play an important role in stabilising consumer gas prices at their efficient level as the competitive environment matures over time.

3.1 Introduction

One of the best ways of ascertaining the net costs and benefits of the current regulatory regime for the gas industry in Australia is to examine how that Regime has impacted on actual *outcomes* for the industry. The net impacts of the Code can be said to be positive if its impact on efficient investment and competition levels in the industry outweigh any costs it may impose on industry players.

As a major player in the gas industry — and one that has considerable interests in the prosperity of that industry generally — BHPB is of the view that the gas industry has developed substantially under the Code. This is the case in relation to the level of investment in new pipelines (noting that growth in pipelines will eventually plateau at an efficient level), as well as for other indicators of industry vitality such as increased competition and diversity in both the upstream and downstream sectors. Evidence on these industry trends is the subject of this chapter.

3.2 Pipelines

Australia's major conventional natural gas reserves are located in the following basins; Carnarvon and Browse in Western Australia, Bonaparte in the Northern Territory, Gippsland in Victoria and the Cooper/Eromanga basin in South Australia and Queensland. These basins are situated in relatively isolated areas and away from gas users. By virtue of this, the Australian gas industry relies on a large network of transmission and distribution pipelines to transport gas from areas of natural gas production to end users — pipeline infrastructure links gas supplies to consumers and as such is one of the key drivers of gas industry development in Australia.

This section provides evidence on the trends relevant to the outcomes in Australia's pipeline (transportation) sector over the period since the early 1990s. The major physical outcomes presented are:

- *growth in the Australia–wide pipeline network*— total kilometres of pipeline; total dollars invested in pipelines and the extent of total customer access to gas pipelines over the period; and
- *major new individual pipeline developments* — new individual pipelines; and new geographical areas that have received new access to distribution pipelines over the period.

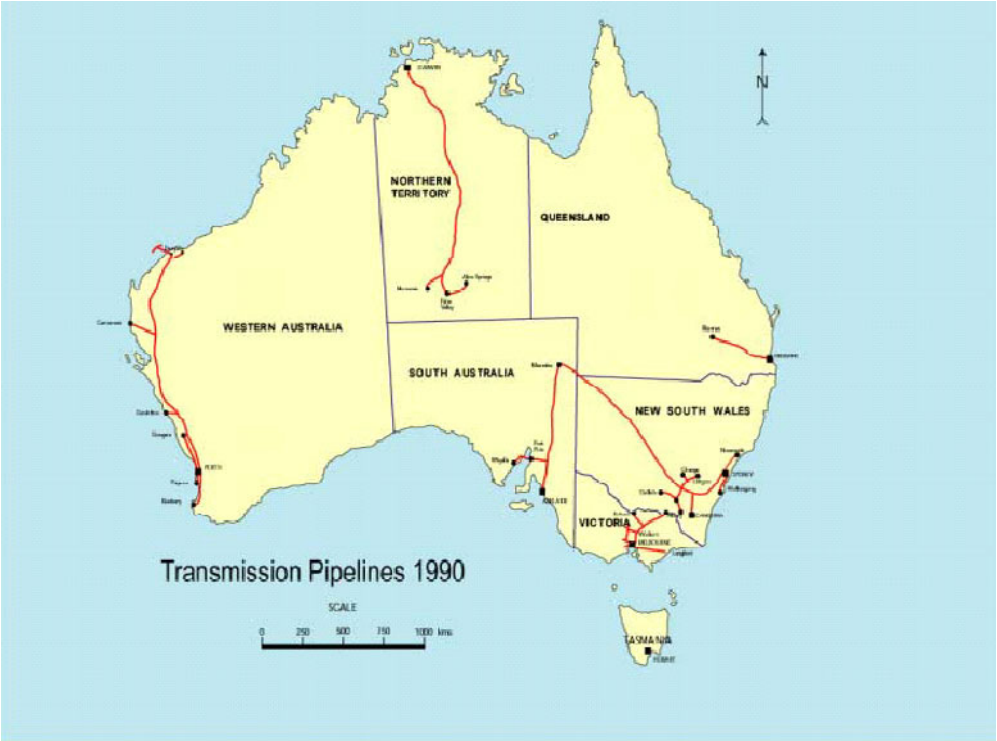
Australia's gas pipeline network

Kilometres of pipeline

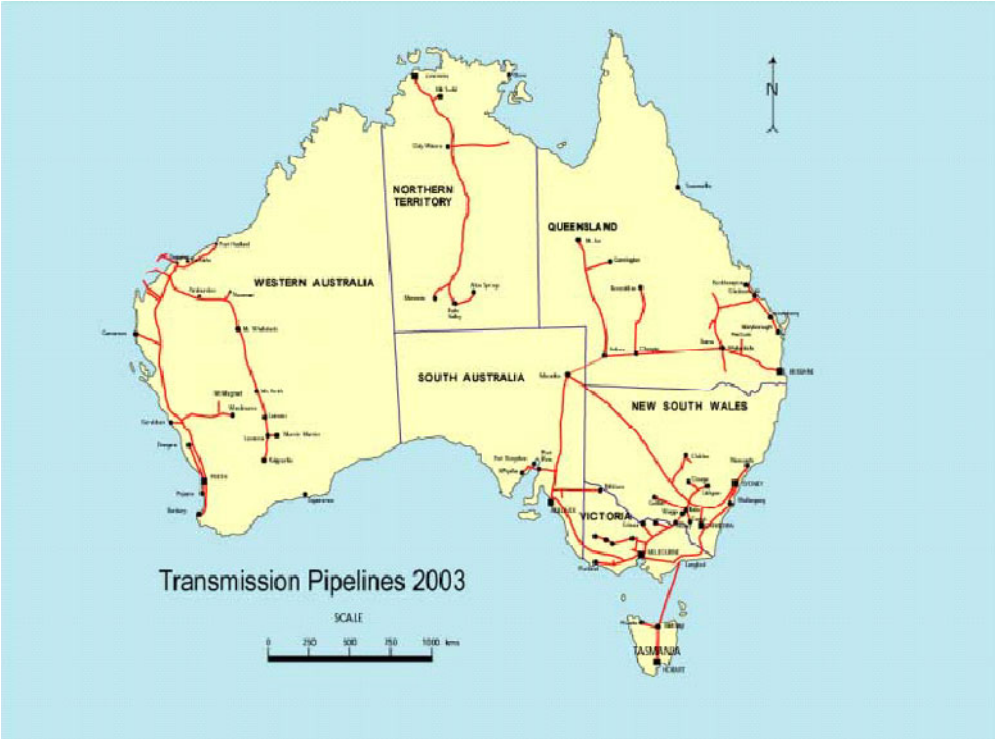
Transmission

The substantial growth in transmission pipelines in Australia since 1990 is shown graphically in Figure 3.1. According to the AGA, there was an 113.9 per cent increase in the length of transmission pipelines in use between 1989 and 2002 — in 1989, the length of gas transmission pipelines in use was 9,399 km, and by 2002 this had increased by 10,710 km to 20,109 km (Figure 3.2).[13]

Figure 3.1 Australia's Gas Transmission Network: 1990 & 2003

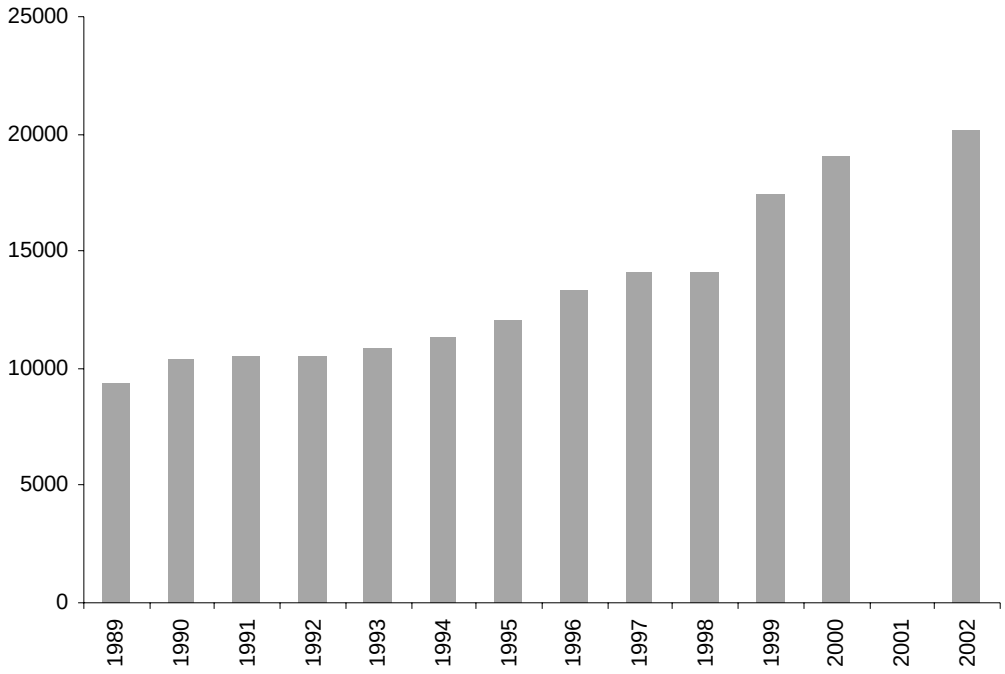


[13] AGA (1990), *Gas Industry Statistics 1989-90*; and AGA (2002), *Gas Statistics Australia 2002*.



Source: Australian Pipeline Trust, Interim Results: 6 Months to December 31 2002, Presentation by Jim McDonald, Sydney 5 March 2003.

Figure 3.2 Kilometres of Natural Gas Transmission Pipeline in Use, Australia 1989 – 2002



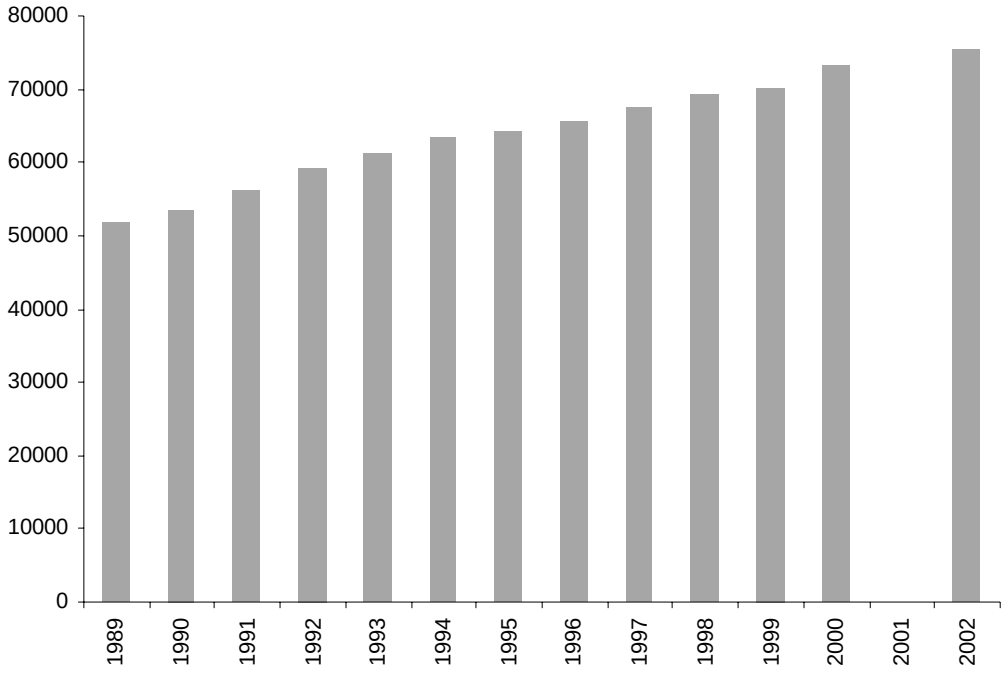
Note*:* These data are based on responses from an annual AGA survey of distributors, pipeline-owners and producers.[14] No data were available for 2001.
Source*:* Australian Gas Association, *Gas Statistics Australia*, various issues.

Distribution

As with transmission pipelines, gas distribution assets have also grown substantially over recent years.

Data from the AGA on the length of distribution pipelines laid over the period 1989 to 2002 for each State and Territory is provided in Figure 3.3. In 1989, the length of distribution pipelines (high, medium and low pressure) in use was 51,906 km — this had increased by 23,543 km to 75,449 km by 2002, an increase of 45 per cent.

Figure 3.3 Kilometres of Natural Gas Reticulation Pipeline Laid and in Use, Australia 1989 - 2002



Note*:* These data are based on responses from an annual AGA survey of distributors, pipeline-owners and producers. No data were available for 2001.
Source*:* Australian Gas Association, *Gas Statistics Australia*, various issues.

[14] Data in this figure and elsewhere in this chapter relies on annual AGA surveys of distributors, pipeline- owners and producers. In publishing this data, the AGA note that the comparability and composition of both ABA and AGA gas industry statistics over time has been affected by recent industry restructuring. As such, some caution is needed in making comparisons of data over time.

Investment patterns

Transmission

In line with the growth in kilometres of pipeline, capital expenditure in transmission pipelines has increased markedly under the Code — since 1990/91, $3.7 billion ($2002) has been invested in gas transmission assets (Table 3.1).

The amount of capital expenditure declined in 1996/97 and 1998/99 but increased strongly in 1998/99 – 2001/2002, reflecting new capital expenditure in a number of projects including the Tasmania Gas Pipeline and the Eastern Gas Pipeline.

Table 3.1 Capital Expenditure on Transmission of Natural Gas, Australia (Constant Prices, December 2002 $m)

Year	Mains and service pipes	Compression and metering	Buildings and other	Total
1990/91	47	1	4	53
1991/92	76	17	5	99
1992/93	43	1	9	53
1993/94	39	3	8	49
1994/95	69	5	23	98
1995/96	679	31	69	779
1996/97	234	106	19	358
1997/98	282	74	8	365
1998/99	165	108	14	286
1999/00	545	25	8	578
2000/01	462	33	3	498
2001/02	455	38	3	497
TOTAL	**3099**	**441**	**173**	**3713**

Source*:* Australian Gas Association, *Gas Statistics Australia*, various issues; ABS (2003), *Consumer Price Index, Catalogue Number 6401.0*. Data adjusted using CPI All Groups, Weighted Average of Eight Capital Cities.

Distribution

Investment in distribution assets has also been substantial since the early 1990s — since 1990/91, $3.3 billion ($2002) has been invested in distribution pipelines (Table 3.2). Growth of capital expenditure in distribution networks increased by up to 15 per cent per annum during this period.

Table 3.2 Capital Expenditure on Distribution of Natural Gas, Australia (Constant Prices, December 2002 $m)

	Storage	Mains and service pipes	Compression and metering	Buildings and other	Total
1990/91	5	128	25	61	218
1991/92	5	114	29	49	197
1992/93	4	168	37	50	260
1993/94	16	180	41	57	294
1994/95	11	228	41	49	329
1995/96	5	219	28	72	324
1996/97	3	192	14	71	281
1997/98	0	214	38	36	288
1998/99	0	221	31	22	274
1999/00	0	307	35	17	359
2000/01	0	204	36	13	253
2001/02	0	170	34	18	222
TOTAL	**50**	**2345**	**389**	**514**	**3298**

Source: Australian Gas Association, *Gas Statistics Australia*, various issues; ABS (2003), *Consumer Price Index, Catalogue Number 6401.0*. Data adjusted using CPI All Groups, Weighted Average of Eight Capital Cities.

Customer access to gas pipelines

The expansion of pipeline networks has meant that natural gas is now widely available across Australia, particularly in Victoria, South Australia and Western Australia, where access to natural gas is available for over 75 per cent of all households (Table 3.3). In particular, substantial growth in household gas accessibility has been observed in Western Australia — in 1995, only 62 per cent of households had access to natural gas; this had increased to 76 per cent of households by 1999.

In this context it is important to note that 100 per cent customer access to gas pipelines will probably never be viable in Australia — some customers are simply too isolated from other households to make their connection to gas pipelines economic. This issue is discussed further in relation to the roll-out of distribution pipelines in Victoria in chapter 4.

Table 3.3 Household Access and Connection to Natural Gas (%)

	1993	1994	1995	1996	1997	1998	1999	2000
New South Wales								
Households connected to gas	27.2	26.3	27.3	28.4	29.3	31.6	31.4	32.9
Households with access to gas mains	54	67.5	60.3	34.9	na	na	na	na
Victoria								
Households connected to gas	74.7	76.1	76.8	77.4	78.4	80.2	82.2	85.4
Households with access to gas mains	88.7	89.3	87.9	90.4	na	88	88	90
Western Australia								
Households connected to gas	46.9	49.8	51.3	52.8	55.6	57.7	57.3	58.5
Households with access to gas mains	na	na	62	na	65	na	76	76
South Australia								
Households connected to gas	49.9	50.5	51.8	52.6	53.1	54	53.4	53.8
Households with access to gas mains	80	80	80	80	80	80	80	80
Queensland								
Households connected to gas	9.4	9.4	9.5	9.4	9.7	10	9.7	9.7
Households with access to gas mains	na	na	na	na	na	na	35	40
ACT								
Households connected to gas	39.1	43.7	46.2	48.5	50.8	53.9	63.6	62.4
Households with access to gas mains	na	50	na	na	na	na	na	na
Australia								
Households connected to gas	40.5	40.9	41.3	41.9	43.3	44.9	45.3	46.7

Note*:* These data are based on responses from an annual AGA survey of distributors, pipeline-owners and producers. Statistics only available up to 2000. The recent edition of *Gas Statistics Australia 2002* does not provide household access and connection information

Source*:* Australian Gas Association*, Gas Statistics Australia* (various issues).

Major new pipeline projects

Transmission

The growth in Australia's pipeline network during the 1990s and more recently has been characterised by a number of major new individual transmission pipelines, including, *inter alia*, the:

- Goldfields Gas Transmission Pipeline (Yarraloola to Newman/Kalgoorlie) in Western Australia;
- the Culcairn interconnect linking gas from the Victorian transmission system to the Moomba to Sydney Pipeline;
- the South West Pipeline in Victoria transporting gas from Iona field to Melbourne;
- Ballera to Wallumbilla pipeline in Queensland;
- Ballera to Mt Isa pipeline in Queensland;
- Tasmanian Gas Pipeline (Longford to Bell Bay/Bell Bay to Hobart);
- Eastern Gas Pipeline (Longford to Hoarsley Park (Sydney)); and
- The SEA Gas pipeline linking Victoria to Adelaide.

A complete list of Australia's major new gas transmission pipelines since 1990 is presented in Table 3.4.

Table 3.4 Major Natural Gas Pipelines, 1990 – 2002

Pipeline	Year Commissioned	Length (km)	Current Owners
New South Wales			
Wodonga to Wagga Wagga	1998	151	APT/GasNet Australia
Central West Pipeline	1998	255	APT
Eastern Gas Pipeline	2000	795	Duke Energy
Queensland			
Southwest Queensland Pipeline	1996	756	Epic Energy
Carpentaria Gas Pipeline	1998	840	APT/SWQ Producers
Gladstone to Bundaberg/Maryborough	2000	300	Origin Energy Asset Mgt /Envestra
South Australia			
Riverland Pipeline	1994	231	Origin Energy Asset Mgt/ Envestra
SEA GAS Pipeline	2002	680	TXU, Origin and International Power
Victoria			
North Paaratte to Portland/Hamilton	1986-95	188	GasNet Australia
Carisbrook to Ararat/Stawell/Horsham	1998	181	Coastal Gas
South West Pipeline	1999	144	GasNet Australia
Mildura Pipeline	1999	190	Origin Energy Asset Mgt/Envestra
Western Australia			
Tubridgi Pipeline System	1991	88	Origin Energy Resources
Kalgoorlie to Kambala	1996	44	Southern Cross
Goldfields Gas Pipeline	1996	1425	GGT Joint Venture
Tasmania			
Tasmanian Gas Pipeline	2002	756	Duke Energy

Source: Australian Gas Association (2003), *Gas Statistics Australia 2002*.

Distribution

New distribution networks have also emerged and as noted, many more regional areas now have access to natural gas as a result of new transmission pipelines passing new areas. New distribution networks in regional areas include, *inter alia*:

- Dubbo and other Western Plains towns in New South Wales;
- Horsham, Cardinia Shire and Mildura in Victoria;
- Rockhampton, Gladstone, Bundaberg in Queensland;
- Kalgoorlie in Western Australia; and
- Mt Gambia, in South Australia.

Table 3.5 provides more detail about new areas that have obtained access to natural gas since 1990 — many new locations across Australia, but particularly in NSW, Victoria, Queensland and Western Australia, have been connected to gas over the last decade or so.

Table 3.5 Expansion of the gas pipeline network – areas accessed between 1990 and 2004

State	1990-95	1995-99	1999-04
New South Wales	Narrandera| Leeton Griffith	Wagga Wagga Dubbo	Wilton Gunnedah Tamworth Narrabri
Victoria	Echuca Portland Hamilton Cobden	Ararat Stawell Horsham Lara	Baddaginnie Mildura
Queensland	Rockhampton Blackall Barcaldine Ballera	Wallumbilla Moura Roma Mount Isa Cannington	Townsville Gladstone Gympie Bundaberg Bunya
Western Australia	Onslow Varanus Island Thevenard Island Tubridgi Griffith Port Hedland	Newman Kambalda Yarraloola Wiluna Jundee Murrin Murrin Burrup Peninsula Karratha Kalgoorlie	Windimurra
South Australia	Snuggery Mt Gambier Katnook Berri Murray Bridge		
Northern Territory	McArthur River Mine		
Tasmania			Bell Bay

Source: Productivity Commission (1999), *Inquiry into Impact of Competition Policy Reforms on Rural and Regional Australia*

Industry Activity

The growth in pipeline infrastructure has been accompanied by growth in the number of transactions involving the transfer of gas pipeline assets. Since 1994, many gas industry assets have been transacted. Table 3.6 shows that during the lead up to and after the inception of the Code, private companies have continued to take an interest in the gas industry by purchasing gas pipeline assets in Australia — since 1994, over $17 billion in gas asset transactions have taken place. In particular, a

number of multinational companies such as Duke Energy, Epic Energy, TXU Pty Ltd have entered the market and acquired assets during this period.

Table 3.6 Major Gas Assets Transacted Since 1994 ($2002)

Date of Sale	Asset	Type of Asset	Purchaser	$m
1994	Moomba-Sydney Pipeline	Transmission	EAPL	660
1995	Pipeline Authority of SA	Transmission	Tenneco	358
1997	Wang (Dongara-Perth Pipeline)	Transmission	CMS Energy	140
	Boral Energy SA/QLD gas networks*	Distribution	Envestra	1,058
	Qld State Gas Pipeline	Transmission	PG&E	189
1998	Dampier-Bunbury Pipeline	Transmission	Epic Energy	2,755
	Qld State Gas Pipeline	Transmission	Duke Energy	229
1999	Westar & Kinetic Energy	Distribution/Retail	Texas Utilities	1,818
	Multinet & Ikon Energy	Distribution/Retail	The Energy Partnership	2,214
	Stratus & Energy 21	Distribution/Retail	Envestra / Origin Energy	1,877
2000	Transmission Pipelines Australia	Transmission	GPU International	1,089
	AGL transmission pipelines*	Transmission	Australian Pipeline Trust	1,315
	Alinta	Distribution/Retail	Utilicorp/public listing	1,032
2001	Gasnet float	Transmission	Public offering	857
2002	Pulse	Retail	AGL	880
2003	Multinet (United Energy)	Distribution	AlintaGas/ AMP Henderson	1,170
TOTAL				**17641**

*Internal restructurings
Note: Data adjusted using CPI All Groups, Weighted Average of Eight Capital Cities.
Source: Origin Energy (2002), Presentation to Institutional Investors in the United States of America, 16 September 2002; BHPB.

The high level of activity in the pipeline sector has resulted in an increase in the diversity of asset ownership. For example, in Victoria the privatisation of pipelines has increased the number of infrastructure holders from a total of one in 1991, to five across transmission and distribution by 2003. However, it should be noted in this context that an increase in the diversity of asset ownership alone does not drive an increase in competition — these asset holders are still natural monopolies in the areas they serve.

3.3 Upstream development

The significant development in pipeline infrastructure since the early 1990s has been accompanied by two major trends in the upstream sector:

- *increases in the level of known reserves* have served to enhance security of supply for gas customers — important indicators in this regard are current reserves and future reserves (i.e. current levels of exploration); and

- *increased diversity* in major basins has enhanced competition levels in the sector — the most important indicators in this regard are the number of market players in the production sector, and the emergence of new supply sources.

These factors are discussed in turn below.

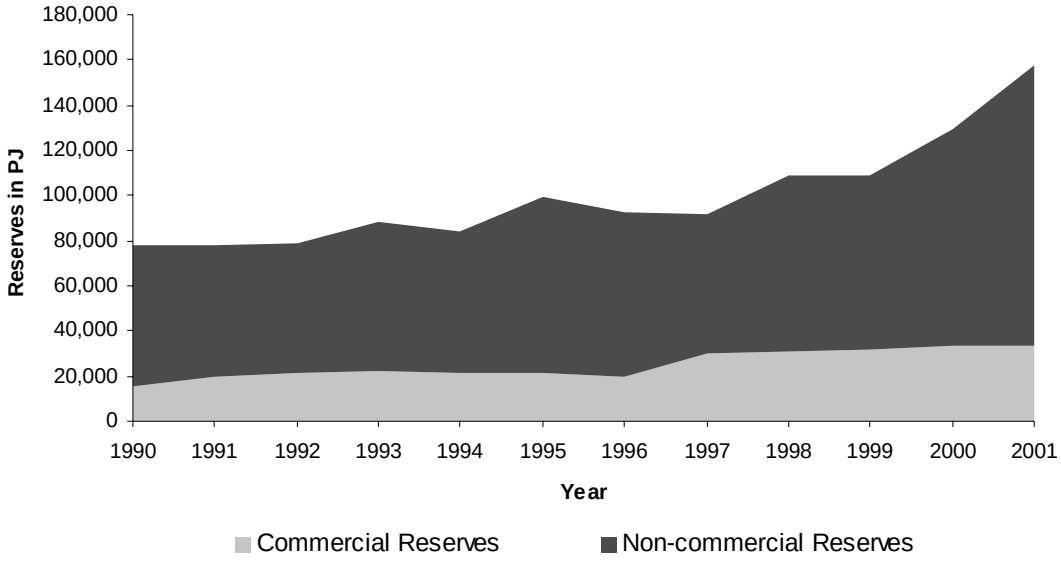
Trends in reserves and exploration

Natural gas reserves

The amount of conventional natural gas reserves in Australia has increased significantly since 1990 (Figure 3.4). Between 1990 and 2001, the volume of total gas reserves (commercial and non-commercial) increased by 102 per cent. More recently, the volume of gas reserves has increased by 99 per cent between 1997 and 2001.

Commercial gas reserves — those reserves that have been proven and can be supplied to markets on a profitable basis (based on current costs of production/extraction and the prevailing price of gas) — have also increased dramatically since 1996. During the period 1999 to 2001, commercial gas reserves increased by 69 per cent.

Figure 3.4 Natural Gas Reserves: Commercial and Non-Commercial



Note: This figure refers to conventional natural gas only — significant volumes of CBM in Queensland and NSW, which now appear viable, are not included in these estimates.

Source: Australian Gas Association, *Gas Statistics Australia* (various issues).

Table 3.7 shows that much of this growth in reserves has been in the Bonaparte (NT), Browse (WA) and Carnarvon (WA) basins, although most other basins have improved or maintained reserve levels since 1991. The total increase in recoverable reserves since 1990 is over 157,000 PJ.

Table 3.7 Recoverable Reserves by Basin (PJ): Eastern Aust., Western Aust. and the Northern Territory

	1991	1994	1997	2001
EASTERN AUST.				
Adavale	23	23	23	0
Bass	374	376	376	376
Bonaparte	7012	7025	7618	27076
Bowen/Surat	308	260	747	229
Cooper/Eromonga	4583	4543	9233	4416
Gippsland	9867	9393	13283	8049
Otway	39	524	575	521
WA/NT				
Amadeus	722	722	883	357
Browse	17209	24497	37301	33671
Carnarvon	38195	52180	53542	81678
Perth	164	172	735	968
Total	**78497**	**99715**	**124314**	**157353**

Note: This table refers to conventional natural gas only — significant volumes of CBM in Queensland and NSW, which now appear viable, are not included in these estimates.
Source: Australian Gas Association, *Gas Statistics Australia*, various issues

New Exploration Permits

A leading indicator of future exploration activity including activity in the gas sector is data on new exploration *permits*. Table 3.8 below shows that during the early 1990s in Eastern Australia a high number of new exploration permits (joint ventures) were approved by the relevant State Government agencies — for example, a total of 31 new permits were awarded on the East Coast in 1995, and at total of 34 awarded in 2001. In Queensland, there were 14 new exploration permits issued in 2000, and a further 12 new exploration permits issued in 2001. These contracts involved new joint ventures from a range of large and companies, such as Origin Energy (Oil Company of Australia) and Santos as well as a number of smaller players including Arrow Energy, BNG (Surat), Falcon Resources, Icon Energy and Kingston Petroleum.

Table 3.8 Historic Awarded Exploration Permits in the East Coast,

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
NSW												
New Permits	4	-	5	9	-	7	2	4	9	2	4	9
No. of companies	3	-	6	10	-	7	2	2	7	2	3	7
Victoria												
New Permits	-	5	7	4	1	8	-	7	5	-	2	3
No. of companies	-	5	11	12	5	12	-	10	8	-	4	5
QLD												
New Permits	7	20	25	31	37	11	9	1	2	3	14	12
No. of companies	9	21	27	35	26	17	9	1	6	4	12	11
SA												
New Permits	10	9	2	1	4	5	3	4	1	2	2	10
No. of companies	17	9	2	2	8	4	2	4	5	12	2	9

Source: BHPB.
Note: The permits above refer to exploration permits approved by the relevant State Government authority. Contracts may be owned by a group of companies (i.e. a joint venture).

Diversity in the upstream sector

In line with the growth in current and future gas reserves, the upstream sector has been characterised in recent years by a marked increase in industry diversity. In particular, as with investments in pipeline assets, the production of natural gas in Australia in existing developments is now undertaken by many more different industry players than was the case in the early 1990s. In addition, a range of *new* gas supply sources has emerged in recent years.

Diversity in existing production

Operators of conventional petroleum production licences for East Austrlian supply basins in 1992 and 2002 are presented in Table 3.9 below. From the table, it is apparent that there has been an increase in the diversity of operators of Joint Ventures of upstream production in both oil and gas. This increase in the diversity is consistent with the increase in exploration permits shown above in Table 3.8 — moreover, diversity in production can be expected to continue to increase over time as exploration continues to expand.

Table 3.9 Operators of Production Licences, 1992 and 2002

Basin	1992	2002
Bowen-Surat	AGL Petroleum Associated Australian Resources Bridge Oil Command CSR Hartogen Energy International Oil Oil Company of Australia	Angari Associated Petroleum Brisbane Petroleum NL Moonie Oil Mosaic Oil Oil Company of Australia Santos Santos Petroleum Operations Sykes Ian Grant Tri-Star Petroleum Company
Cooper/Eromanga	Ampolex Minora Resources Santos	Associated Petroleum Australian Gasfields Chimelle Petroleum IOR Exploration and Petroleum Mosaic Oil Oil Company of Australia Santos Transoil Vernon E Faulconer Australia
Otway Basin	Air Liquide Australia Gas and Fuel Corporation of Victoria Ultramar	Air Liquide Australia Boggy Creek Origin Energy Petroleum Santos TXU Gas Storage
Gippsland	Esso Australia//BHP	Esso Australia//BHP Billiton OMV Timor Sea

Source: Petroleum Resources Branch, Bureau of Resources Sciences (1993), *Oil gas resources of Australia 1992*; Department of Industry, Tourism and Resources (2002), *Geoscience Australia: Petroleum exploration and development titles*.

This increase in diversity in upstream production has been accompanied by a substantial number of new sales contracts from existing developments, in particular Bass Strait (Table 3.10). The nature of these new sales contracts suggest that diversification is occurring for sellers as well as buyers — gas producers are diversifying their sales to buyers other than a single foundation buyer, and gas buyers are using competition between suppliers to diversify their sources of supply. For example, currently the majority of gas entering the Victorian market is supplied under a long-term contract between BHP Billiton/Esso and the State Government owned Gascor (Gascor then on-sells the gas to number of retailers) . This contract is due to expire towards the end of the decade. Recently BHP Billiton Limited and Esso Australia Resources announced a MOU with TXU Electricity Ltd (TXU) for the sale of Gippsland gas.[15] The MOU covers the sale of 860 petajoules of Gippsland gas to TXU for delivery mainly into Victoria via the Gasnet system in the period 2005 to 2017. The MOU with TXU includes gas for delivery into Victoria in the period following the expiry of the Gascor contract.

[15] BHP Billiton (2002), *Media Announcement: BHP Billiton Signs Memorandum of Understanding with TXU*, 13 December 2002.

Similarly, on 18 December 2002, BHP Billiton Limited and Esso Australia Resources signed a Memorandum of Understanding (MOU) with AGL Gas for the sale of gas from the same existing gas development at Gippsland.[16] The MOU covers the sale of 563 petajoules of Gippsland gas to AGL Gas over 10 years from 2004 to 2013. The gas will be delivered into Victoria via the Gasnet pipelines system, and into New South Wales and the ACT via the Eastern Gas Pipeline.

[16] Ibid.

Table 3.10 Recent significant sales from existing developments

Field	Announced	Production due on-stream	Joint venture partners	Sale contracts
SWQ Gas Producers	2003	2003		Sale of 15 PJ over 3 years to Pasminco Century mine
Bass Strait JV	2002	2005	BHPB (50%) Esso (50%)	December 2002: JV sale to TXU. 860PJ over 2005-17
Bass Strait JV	2002	2004	BHPB (50%) Esso (50%)	November 2002: JV sale to TXU. Up to 20PJ/pa over 2004-07
Bass Strait JV	2002	2004	BHPB (50%) Esso (50%)	December 2002: JV sale to AGL. 563PJ over 2004-2013
	2002	2005		Origin and Oil Company of Australia sale to AGL. 340 PJ over 15 years.[17]
Cooper Basin Producers	2002	2003		JV sale to AGL. Up to 505PJ over 2003- 2016[18]
Bass Strait JV	2001	2002	BHPB (50%) Esso (50%)	JV - Jul 1999 Sale to Duke substantial volumes for Tasmania term 15yrs from 2002
Bass Strait JV	-	2000	BHPB (50%) Esso (50%)	JV Sale for BHP Steel, One Steel & Sith.
AGL	1999	2001	AGL (100%)	AGL sale to National Power. Up to 50PJ over 5 years.

[17] Note of the 340PJ 195PJ shall be supplied from the Fairview field and the other 145 PJ shall come from other Origin & OCA CBM sources in Queensland.

[18] Volume is from both SA & Qld sections of the Cooper Basin JV SA section Santos 59.8%, Esso 20.2%, Origin 13.2%, Novus 4.75%& OMV 2.1% Old Section Santos 60.1%, Esso 23.2% & Origin 16.7%

Emergence of new supply sources

As well as an increase in diversity in existing markets, increasing pipeline infrastructure and increased levels of reserves exploration activity has resulted in the emergence of substantial new gas supply sources in Eastern Australia. The emergence of these new supply sources has lead to a substantial increase in supply competition, and increased the security of supply for gas customers.

In particular, it is worth noting that since 1999:

- there has been a total of 14 new supply sources in Eastern Australia committed (or likely to be committed in the next two years). Many of these new producers are entirely new players to the production sector; and
- coal bed methane (CBM) has emerged as a prominent new supply source with 750 -1000PJ of new contracts for coal bed methane written over the last few years. This growth can be expected to continue — ABARE estimates that Queensland and NSW alone hold reserves of CBM equivalent to over 250,000 PJ of energy, representing over ten times the resources available from conventional gas sources in Eastern Australia.[19]

Table 3.11 shows these new gas developments and associated underpinning sales contracts. Significant new committed developments include:

- Patricia/Baleen — OMV, Santos, and Mitsubishi Corp have developed this field with a gas supply agreement with Energex in place;
- Yolla — Origin, Australian Worldwide Exploration, CalEnergy and Santos have entered into a binding sales agreement to supply gas to Origin Energy's retail arm;
- Onshore Otway — Santos, is separately marketing gas from permits held solely, and with Beach Petroleum, through its Heytesbury gas processing facility. Gas production from the onshore Otways delivered into Victoria has increased from approximately 10 to 30 TJ per day; and
- Minerva — BHPB and Santos separately market their equity shares of gas from the Minerva gas field offshore from Victoria.
- Thylacine and Geographe — TXU has executed a heads of agreement for the purchase of Woodside's share of this recently discovered gas field from 2006;
- Moranbah — CH4 and BHPB have a contract to supply approximately 290 PJ over 15 years to Enertrade (CBM);

[19] Dickson, A., and Noble, K., (2003), 'Eastern Australia's gas supply and demand balance', *APPEA Journal 2003.*

- Camden – Sydney Gas Co has entered in to two significant sales contracts with AGL to supply 100PJ over 10yrs and
- Anglo German Creek — Anglo Coal has negotiated significant CBM-based sales to Energex and CBM Energy Developments.

These developments coincide directly with the development of transmission facilities, and can be expected to contribute to further future competition in wholesale gas production.

These developments in the upstream sector illustrate that competition in the upstream sector is thriving in Eastern Australia. The reforms of the 1990s — including the development of an open access regime and the introduction of customer contestability — has played a significant (if indirect) role in driving this new world.

A review of the West Australian market over the 1990's would also show a increase in supply sources and customers linked by new transmission pipelines.

Table 3.11 New Gas Field Developments and Sale Contracts

Field	Development Committed	Production due on-stream	Joint venture partners	Sale contracts
Conventional				
Yolla	2003	2004	Origin Energy (37.5%) AWE (30%) CalEnergy (20%) Wandoo Petroleum (12.5 %)	March 2001: JV sale to Origin 260PJ @ 20PJ/pa over 13 years.
Onshore Otway (PEP154/153)	2002	2002	Santos (90 – 100%) Beach (0-10%)	May 2002: JV sale to a retailer. 25PJ over 2.5y years.
Minerva	2002	2004	BHPB (90%) Santos (10%)	March 2002: BHPB sale to National Power. Approximately 300PJ over 10 years
Patricia/Baleen	2001	2002	OMV (40%) Santos (20%) Mitsubishi (40%)	May 2001: JV sale to Energex (approx 60PJ). No term given.
Onshore Otway (PEP108)	1999	1999	Santos (100%)	March 1999: JV sale to Gasco. 11PJ over 3.5 years.
Blacktip	No	2007	Woodside (70% approx) AGIP (30% approx.)	June 2003: JV sale to Alcan. 800PJ @ 40 PJ/pa for 20yrs.
Geographe/Thylacine	No	2006	Woodside (51.55%) Origin (29.75%) Benaris Int. (12.7%) CalEnergy (6%)	August 2002: Woodside sale to TXU. Approximately 400PJ, no term given,
Coal Bed Methane				
Anglo Coal (Moura)	2003	2003	Anglo Coal, Mitsui Moura	May 2003: JV sale to Energex. 78 PJ over 12 years.
Anglo Coal (German Creek)	2003	n.a.	Anglo Coal (100%)	June 2003: Sale to CBM Energy Developments for a 32 MW power plant based on waste.
Moranbah	2003	2005	CH4(50%), BHPB(50%)	June 2002: JV sale to Enertrade. Approximately 290PJ over 15 years
Camden Stage 2	2002	2003	Sydney Gas Co (100%)	December 2002: Sale to AGL. Up to 10PJ/pa over 10 years
Scotia	2000	2002	Santos (100%)	Sale to CS Energy. 120PJ over a 10-15 year term
Camden Stage 1	1999	2001	Sydney Gas Co (100%)	August 1999: Sale to AGL all production from the first 25 wells.
Berwyndale South	No	2004/2005	QGC (50%), CSE (50%)	December 2002: JV sale to CS Energy. 90PJ over 15 years.
Arrow	No	2004/2005	Arrow Energy (100%)	April 2003: JV sale to CS Energy. Up to 60PJ over 15 years
Peat/Moura	n.a.	2000	OCA (100%)	Various contracts including BP Bulwer Island cogeneration over a 20 years

3.4 Downstream development

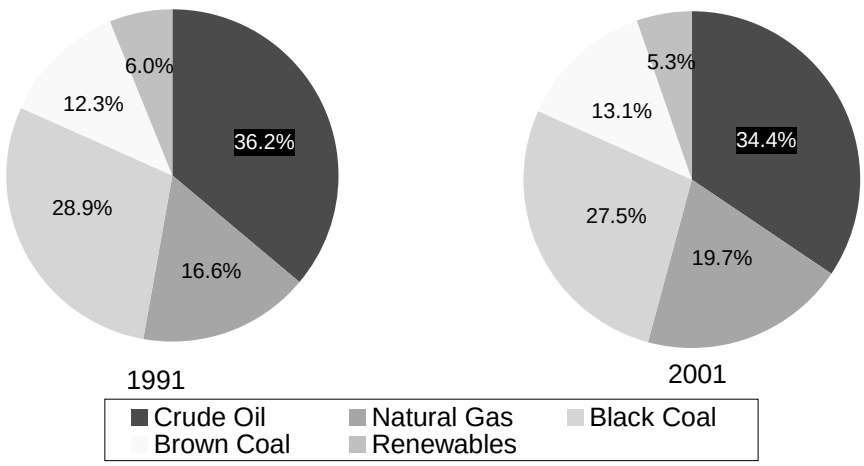
Ultimately, the benefits of effective access regulation should be felt by gas consumers. This section examines the performance of the downstream industry from the perspective of the consumer, paying particular attention to the following indicators of industry vitality in the downstream sector:

- use of natural gas as an energy source;
- consumption of natural gas, including take-up and accessibility measures; and
- trends in the price of gas.

Natural gas as an energy source

Natural gas has experienced rapid growth as a fuel source for Australia's energy requirements in recent years. Figure 3.5 shows that the share of all energy sourced from natural gas rose from 16.6 per cent of the nation's energy fuel source in 1991 to 19.7 per cent in 2001. The extent of this growth is emphasised by the strong economic growth that occurred during this period, and by the fact that other fuel sources such as crude oil and black coal have experienced declining shares during this period (from 36.2 per cent to 34.4 per cent, and 28.9 per cent to 27.5 per cent, respectively).

Figure 3.5 Energy Use by Fuel Type, 1990 and 2001

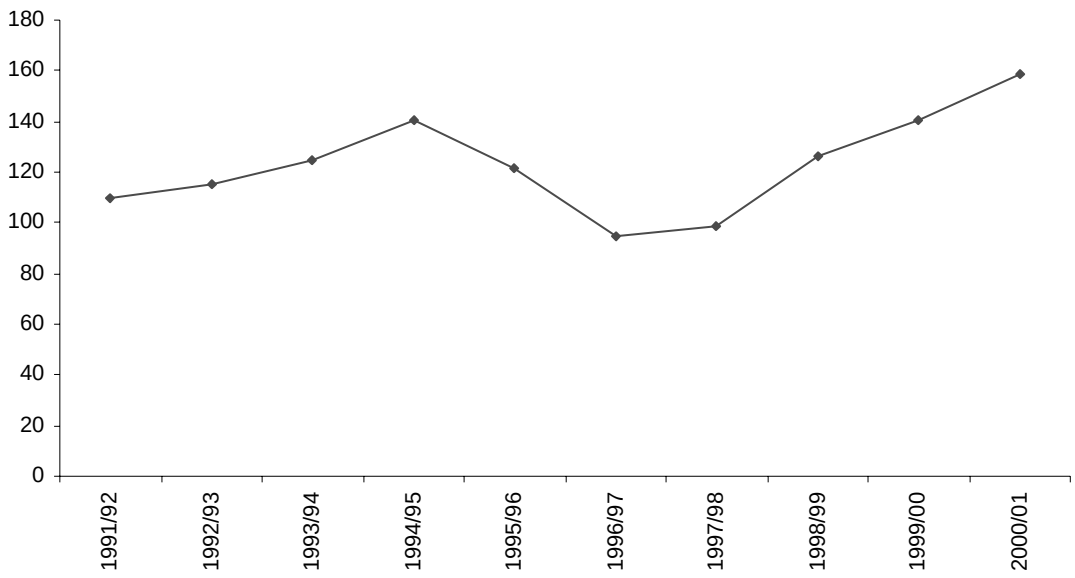


Source: Australian Gas Association, *Gas Statistics Australia* (various issues).

The consumption of natural gas in gas-fired electricity generation has fluctuated over the period 1991-2002 (Figure 3.6). The use of natural gas in electricity generation declined between 1993 and 1997, largely as a result of interstate connections in power markets and the consolidation of power generators. In particular, there has been decline in gas-fired generation in Victoria and South Australia as a result of the expiry of a number of long-term take or pay contracts and the operation of the National Electricity Market changing the dispatch profile of some significant gas fired power stations.

However, since 1998, the use of natural gas in gas-fired generation has increased. In particular, New South Wales and Queensland have introduced new gas fired generation plants for the first time in the mid –to-late 1990s.

Figure 3.6 Natural Gas Used in Thermal Electricity (PJ)



Source: Australian Gas Association, *Gas Statistics Australia* (various issues).

Consumption of gas

In line with solid gains in both the pipeline and upstream industry sectors, consumption of gas by Australians has increased steadily since the introduction of the current regulatory regime:

- Since 1990, there has been an increase in the number of natural gas customers, both from the residential and commercial/industrial sectors. As observed in Table 3.12, the number of residential customers has increased by 40 per cent

from 1990 to 2002. Correspondingly, the number of commercial and industrial customers has increased by 33 per cent.

- Natural gas consumption increased by 49 per cent between 1990/91 and 2000/01.
- As observed in Figure 3.7, residential, mining, manufacturing and electricity generation sectors are all now using a higher proportion of natural gas in terms of total energy consumed. Since 1990, natural gas has increased from 27.3 to 30.4 per cent of total energy consumed by the residential sector, 51.4 to 55.6 per cent in the mining sector, 28.2 to 33.0 per cent in the manufacturing sector and 11.3 to 15.3 per cent in the electricity generation sector.

Table 3.12 Number of Natural Gas Retail Customers ('000)

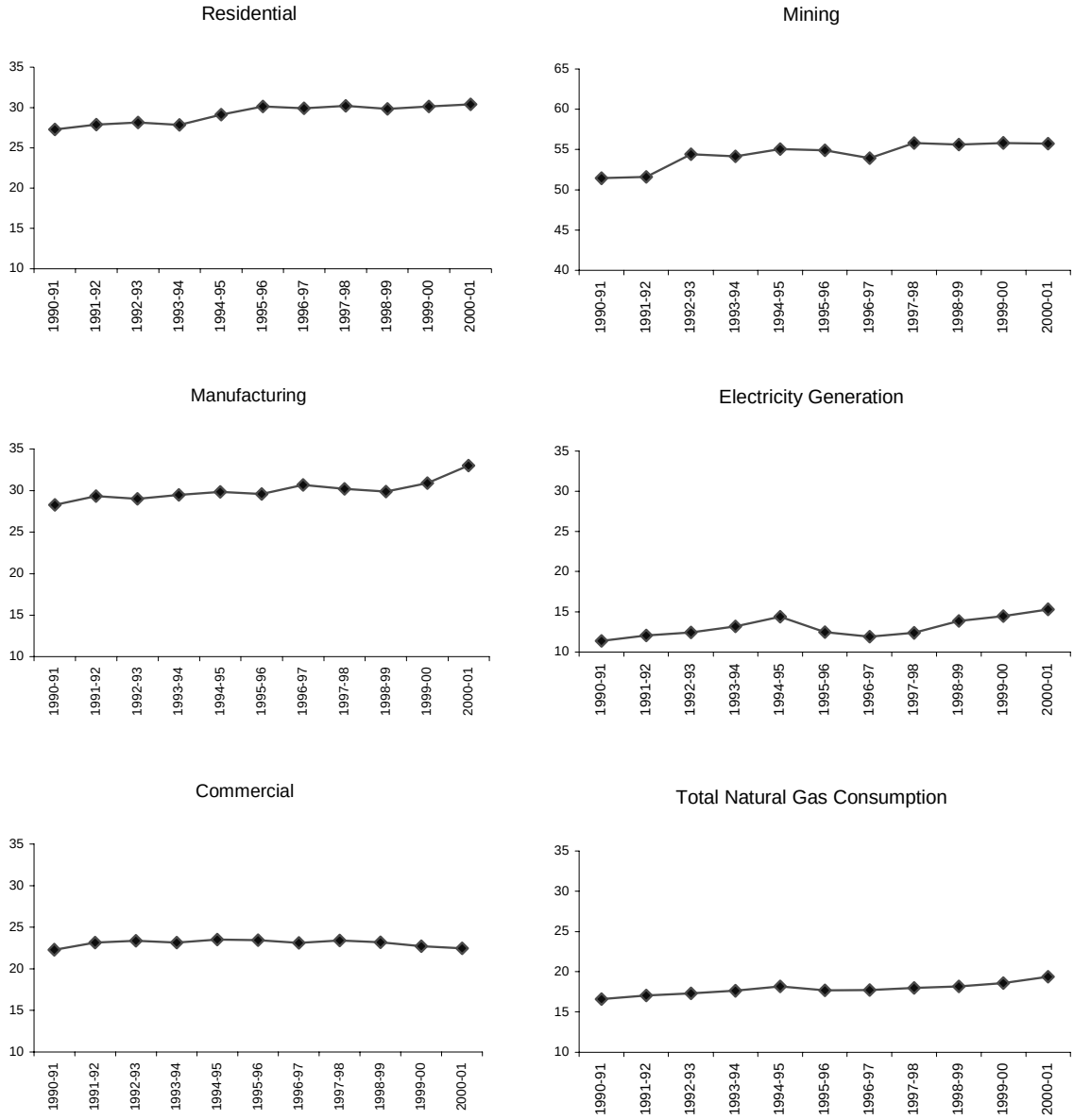
Year	Residential	Commercial and Industrial	Total
1990/91	2 400	79	2 479
1991/92	2 481	84	2 565
1992/93	2 570	87	2 657
1993/94	2 622	86	2 708
1994/95	2 716	84	2 800
1995/96	2 811	86	2 897
1996/97	2 891	89	2 980
1997/98	3 011	87	3 098
1998/99	3 096	92	3 188
1999/00	3 223	115	3 338
2000/01	na	na	na
2001/02	3 361	105	3 467

Note: Data for 2000/01 not available.
Source: Australian Gas Association, *Gas Statistics Australia* (various issues).

Connection to natural gas

In line with the increase in gas consumption, household connectivity to natural gas has also increased. The data shown in Table 3.3 above indicate that in nearly all States and Territories, a greater proportion of households are connected to natural gas now than was the case in the early 1990s. Growth in household natural gas connectivity is most prominent in the ACT, Western Australia and Victoria where connectivity is above 50 per cent.

Figure 3.7 Natural Gas as a Proportion of Total Energy Consumption



Source: ABARE, (unpublished)

Price trends

Household prices

Price trends for household retail gas and electricity for major capital cities with access to natural gas are presented in Figure 3.8. On average, the real price of household retail gas has increased overall in Australia by about 7 per cent from

1990 levels. The highest real increases during this 11 year period occurred in Darwin (30 per cent), Adelaide (15 per cent) and Canberra (14 per cent). Conversely, Melbourne, Brisbane and Perth all experienced declines in real gas prices.

The wide variability in household prices across Australia shown in Figure 3.10 reflects the fact that many factors combine to determine the gas price in a given jurisdiction. For instance:

- *climate* — jurisdictions with cooler climates can be expected to have higher (and more volatile) demand for gas. This can be expected to influence prices;
- *full retail contestability (FRC)* — as each jurisdiction moves to FRC there will be adjustment from the regulated price to a competitive market price. Differences in relative prices and price movements between jurisdictions can be expected to reflect the different stages in the implementation of FRC in each jurisdiction;
- *level of regulated prices* — similarly, different approaches to gas pricing in each jurisdiction prior to FRC will mean that in some States, the regulated gas price may have been artificially high before FRC while in others it may have been too low (relative to the competitive market price). The direction of the adjustment to the competitive price might therefore differ across jurisdictions; and
- *phasing out of alleged cross subsidies* — related to this, in some markets, incumbents asserted that pre–FRC price structures entailed cross subsidies from some customer classes to others. Regulators in some jurisdictions have allowed a price adjustment to compensate incumbents for the unwinding of the alleged cross-subsidisation phase out, price movements will take time to adjust to the competitive market price.

While one of the aims of the current regulatory regime is to generate lower gas prices for consumers, because of the wide range of potentially countervailing factors impacting on prices, it is difficult to distil the Regime's direct impact on prices to date. Moreover, because FRC is at different stages in different States, it is likely that it will be a number of years before the full impact of the reform process and accompanying regulation on gas prices plays itself out. Nevertheless, it is certain that the regulatory regime will play an important role in stabilising consumer gas prices at their efficient level as the competitive environment matures over time.

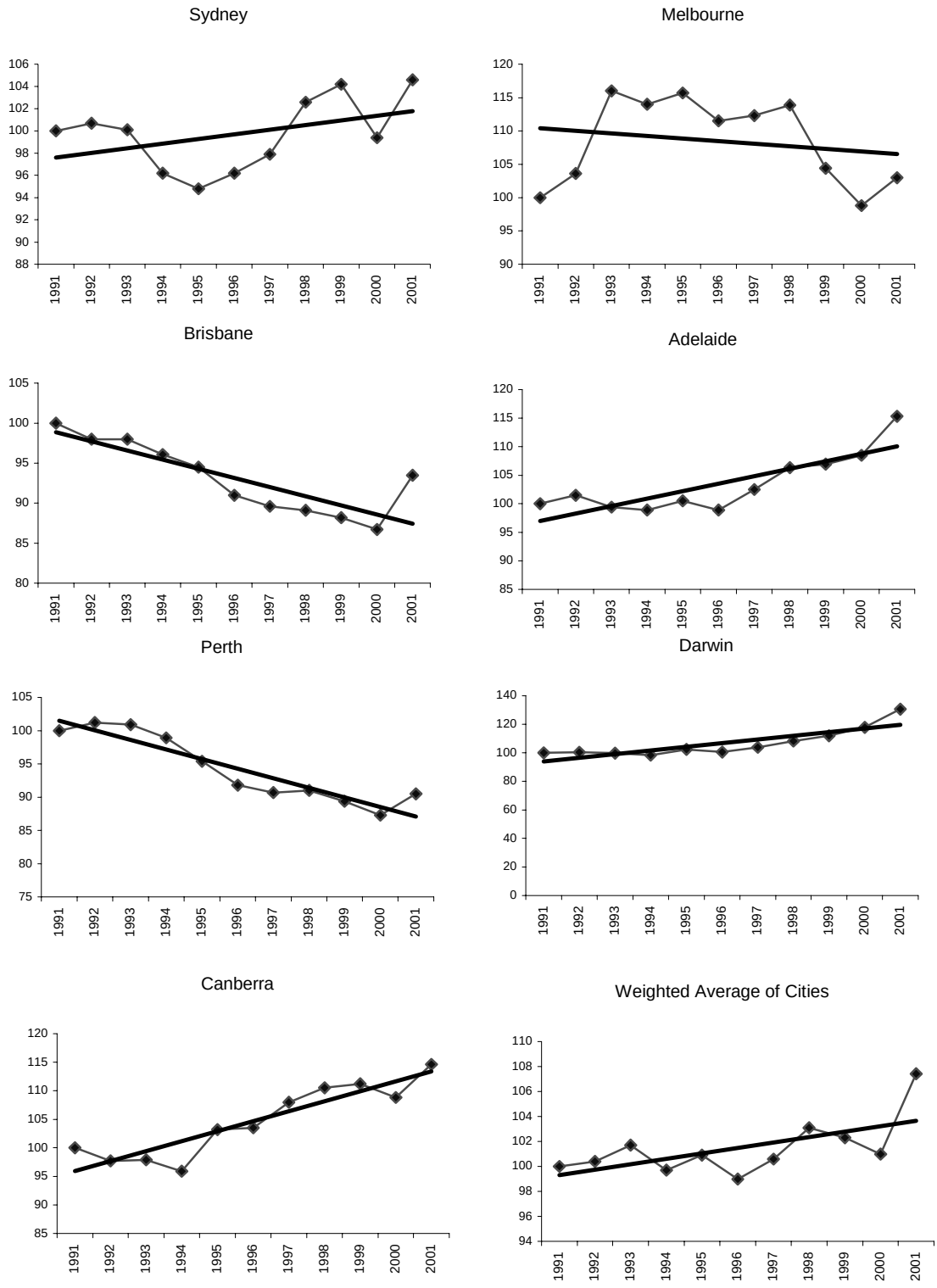
Prices for industrial and commercial customers

It is even more difficult to ascertain the impact of the regime on prices for industrial and commercial gas users — virtually no information on the prices paid by these consumers is available in the public domain.

Nevertheless, it is possible to argue that regulation has freed industrial and commercial customers from being franchise customers, and is likely to have given them much greater flexibility in negotiating the best prices from suppliers. For example, the regime that applied prior to the current one in NSW was one in which prices for large customers (10TJ/pa or more) were set by negotiation (with no regulatory oversight) between the monopoly supplier AGL and the customer. It is our view that this scenario represents one in which market power rested solely with the monopoly supplier in AGL, and that customers were given very little option but to accept the price offered by AGL, or source an alternative fuel. The views of AGL in relation to reasonable customer expectations in NSW prior to the introduction of the current Regime support this view. In a letter to IPART in July 1999 in relation to an access arrangement for the NSW Network, AGL argued that contract customers (10TJ/pa or more) could "reasonably have expected prices would not be reduced" under the previous regime.[20] This view suggests that prices were previously set without reference to the costs of the transportation services actually delivered to customers. In contrast, it is fair to assume that under a competitive market environment — such as that since generated by the current regulatory Regime — large customers could assume with more confidence that prices would be set by competition and that the transportation portion of their price would be cost reflective. This represents a more efficient outcome for customers, and for the economy more generally.

[20] Letter from Bruce Connery, GM Regulatory Affairs, AGL to Dr T. G. Parry, Chairman, IPART on 23 July 1999.

Figure 3.8 Real Retail Household Gas Price Trends, Capital Cities (Price Index)



Source*:* Australian Gas Association (2003) *Gas Statistics Australia 2002.*

3.5 Conclusions

The current regulatory regime has overseen a period of strong and sustained growth in all sectors of the gas industry, and as such has made substantial progress towards achieving COAG's original goals for reform.

Industry development has been particularly strong in the areas of pipeline investment and production. In particular, a number of major new greenfields pipelines have proceeded, and many new exploration permits, sale contracts and new sources of supply have been established. The enhanced activity in upstream markets has been undertaken by a range of new players, suggesting that sustainable upstream competition now exists, in both the West Australian and East Coast markets. Key indicators of this industry vitality include that:

- Since 1990/91 more than $6 billion has been invested in transmission and distribution assets each year. As a result, between 1993 and 2002, total transmission pipeline infrastructure has increased by 86 per cent, and total distribution infrastructure by 23 per cent.
- Over $17 billion in gas asset transactions have been undertaken since 1994, indicating that companies are willing to invest substantial capital in the industry.
- A number of major new supply sources have emerged including the Patricia/Baleen, Yolla and Otway fields, as well as substantial CBM developments in NSW. Each of the new supply sources has substantial sales contracts already in place.
- Gas is currently nearly 20 per cent of the total energy supplied in Australia, an increase of 3 per cent since 1990. The AGA expects this to grow to 22 per cent by 2005 and to 28 per cent by 2014–15.[21]

Related to this substantial activity in the industry since the early 1990s, a significant pipeline network — funded by private capital — has now been established in Australia:

- there is now a connection of Victoria and New South Wales through the Interconnect and the Eastern Gas Pipeline;
- two interfaces now exist in Queensland between the Surat and Cooper Basin fields;
- New South Wales has had gas extended to the central west region with a pipeline to Dubbo;

21 ACCC (2002), *Draft Greenfields Guideline for Natural Gas Transmission Pipelines*.

- gas fired power is expanding in South Australia, Victoria, Queensland and the Northern Territory;
- Tasmania has to received supplies of natural gas for the first time; and
- Adelaide is about to be connected to the Victorian system, and plans are underway to connect Esperance, Albany and Telfer in Western Australia.

All of this new investment in gas pipelines was undertaken during the period of the Regime — that is, after 1991 when the intention to introduce access regulation was widely known and understood. This evidence is directly contrary to arguments that the Regime has stymied new investment.

While the benefits of regulation are beginning to be felt in some downstream markets, prices have yet to fall in all markets. At this stage, it is difficult to determine whether all the benefits of regulation have been passed onto consumers. This represents a challenge for the Regime going forward, and is discussed further in part 3.

Chapter Four

Deferred Projects and Other Effects of Access Regulation

4.1 Introduction

As discussed in chapter 2, a common claim made by pipeline owners and their representatives is that the regulatory framework for gas pipelines in Australia is 'chilling' new investment in the industry. Related claims include that the actions of regulators have lead to the reduction in the values of regulated businesses, and caused an outflow of funds from international investors.

This chapter addresses these comments. First, it discusses the full background of two gas transmission projects that are commonly cited as evidence of the projects that have been deferred – namely Epic Energy's proposed Darwin to Moomba (DMP) project, and ExxonMobil's proposed PNG to Queensland (PNG) proposal. Contrary to views held by the pipeline industry, it is our view that the failure of these two projects to proceed to date is attributable entirely to competitive economic forces, and is unrelated to deficiencies in the regulatory framework. In particular, the chapter examines the role that the following factors have played in the deferral of these projects to date:

- availability of a gas supply source for the project itself;
- competing sources of gas supply; and
- uncertainty about regulatory arrangements.

We then discuss the reasons behind the deferral of several distribution projects in Victoria. Lastly, the chapter discusses the flexibility available for new projects under the Regime, including a number of case studies of successful gas projects that have proceeded both within and from outside the current regulatory framework.

4.2 The DMP and PNG pipeline projects

The deferral of both the DMP and PNG pipeline projects can be attributed to two driving factors:

- the failure of project sponsors and other stakeholders to generate viable scenarios for the development of the Timor Sea and PNG gas resources respectively; and
- related to this, the emergence of new, more competitive gas supply sources in Eastern Australia.

These issues are discussed in turn below.

Role of gas supply in project deferrals

Both the DMP and the PNG pipelines form part of much broader gas resource developments. The success of these broader projects is dependent on a wide range of factors — in particular, neither project could realistically commit to providing gas supply until sufficient underpinning load has been secured, or until major public policy issues such as fiscal arrangements with stakeholder governments have been resolved. The history of both of these projects shows that the failure of the pipelines to proceed to date has occurred largely as a by-product of the failure of the project proponents to negotiate viable commercial arrangements for the broader development of the Timor Sea and PNG gas resources. In the main, these factors are unrelated to the actual pipelines themselves.

DMP

The DMP was part of a broader project to develop the Bayu-Undan (3.4 tcf) and Sunrise gas fields (9.2 tcf) in the Timor Sea. Its success or failure was ultimately linked to the success or failure of the broader effort to bring Timor gas onshore, as well as to the transportation of this gas to Eastern gas markets. This section will show that there was a wide range of factors that contributed to the decision not to bring Timor gas to Eastern Australia, and that the deferral of the DMP can be attributed almost entirely to this broader outcome.

A proposal to supply Timor Sea gas into the Australian domestic market was first announced in November 1999 as an alliance between Phillips Petroleum (operator of the Bayu-Undan fields) and Epic Energy. The project involved a 500km sub sea pipeline to bring gas onshore. In order for the this major investment in pipeline infrastructure to be viable, the pipeline needed to supply a minimum quantity of gas — demand for this supply could come from domestic markets, both in Darwin and elsewhere in Australia — and/or from LNG activities. During 2000 the participants

in the Sunrise gas field (Woodside operator) entered in to a regional cooperation agreement with the Bayu-Undan participants covering gas supply to Darwin and beyond. The benefits of this cooperation were forecast to be substantial including forecast lower capital expenditure of $1b and "higher and more certain upstream value".[22]

In December 2000, it was estimated that in order for it to be viable to bring gas from the Timor Sea onshore into Darwin, the minimum level of demand required was 1300 mmscf/d (or approximately 475 PJ/pa).[23] Initial development plans proposed that this would be split between gas for the domestic Australian market and an onshore LNG plant. At that time, proposed domestic customers for the gas were Methanex (110PJ/pa), Nabalco (estimated at 40PJ/pa), and PAWA (approx 15-20PJ/pa). The LNG plant would require 220PJ/pa leaving other East Australian markets to be captured — via the DMP — in the order of 90-110PJ/pa.

The critical point in this context is that the DMP was only a small part of the overall project to develop Timor gas — while the DMP was an important component of the total underpinning load required to make onshore gas viable, it was only about 20 per cent of the total onshore market that had to be captured. Moreover, the structure of the development proposal for Timor gas was clearly a critical driver of the viability of the DMP — the DMP would only be needed if 1) Timor gas came onshore and 2) if some of this onshore gas was then to be transported to Eastern markets. As the alternative development proposals for Timor gas developed over time, it became apparent that neither of these conditions would be met, at least in the short term.

Firstly, major Darwin-based customers such as Methanex withdrew from negotiations (Methanex eventually moved a smaller project to Western Australia.) This meant that additional demand would need to be sourced from alternative Darwin-based projects or from Eastern markets in order to make the project viable. As discussed in detail below, substantial new demand from Eastern markets failed to emerge in the short term, largely because of the emergence of new, more competitive gas supply sources. Moreover, in May 2001, APT announced plans for a competing pipeline to link gas supplies in the Northern Territory, Queensland, NSW, South Australia and Victoria — this meant that the DMP was now directly competing with another proposed pipeline for foundation customers.[24]

Second, and following the loss of major onshore customers, the operators of the Sunrise and Bayu-Undan fields identified alternative and separate development

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[22] Woodside Petroleum Ltd (2000), *Full Year Results: Feb 2001*, presentation available on Woodside web site (www.woodside.com.au).

[23] Op-cit.

[24] APT Press Release, Pipeline to link Northern Australian gas to Eastern Australia, 9 May 2001.

prospects that would not require the DMP. Phillips signed a LOI with Tepco for 3mtpa of LNG supply for 17 years — this would bring Timor gas onshore, although the plant would effectively exhaust the supplies available from the Bayu–Undan field, leaving none for Eastern markets even if customers could be found. Similarly, in February 2002 Woodside announced that a stand alone Floating LNG project was the preferred development proposal for Sunrise. Further in May 2002 they announced that despite "[holding] discussions with about 30 potential onshore gas customers [they] were unable to create a viable domestic gas project" and that a stand-alone 5mtpa floating LNG proposal was potentially viable and was their preferred development option for the Sunrise resource.[25]

Thirdly, fiscal arrangements between Australia and East Timor — which are a key driver of the commerciality of any proposal to develop resources in the Timor Sea — remained unresolved. These issues have been specifically attributed to why the Bayu-Undan Joint Venture -'delayed final approval of the proposed LNG arrangement with Tepco, but could also be expected to have played a role in reducing the attractiveness of all Timor Sea development proposals, including those that might involve the DMP. In December 2001 Phillips stated that they:

> …welcome the decision by the East Timor Council of Ministers to endorse the understanding on a tax and fiscal package that will allow the Bayu-Undan gas development in the Timor Sea to proceed…we now await ratification of the agreement by Australia so we can proceed with finalising gas sales arrangements that will secure project development.[26]

However the Australian Government did not ratify the tax treaty until early 2003. Prior to this point, it could not be confirmed that the resource development was economic. On this basis, the project was only really a viable proposition after this (very recent) date.

The Bayu-Undan LNG project was given final approval by the Joint Venture earlier this year after the fiscal terms were finally locked. The Sunrise Joint Venture's plans for a stand alone floating LNG plant have been shelved indefinitely:

> "The Sunrise Joint Venture …today announced their agreement on the key findings of the review of development options for Greater Sunrise. Through the review process the Joint Venture has undertaken a thorough analysis of a proposal based on piping gas 500km to shore for sale in Darwin and elsewhere in Australia and an alternative proposal by Shell, to supply LNG to North America from a floating LNG facility. The review has found that neither proposal to be viable. Both domestic customers and Shell have been advised accordingly.
>
> Woodside press release, 5/12/02

[25] Woodside Petroleum Ltd (2002), Investor Presentation May 02 available on Woodside web site: www.woodside.com.au

[26] Phillips press release, 21/12/01.

Role of regulatory uncertainty in delaying the DMP

Rather than citing competing supply and lack of gas as reasons behind their project's deferral, the pipeline industry contends that regulatory uncertainty is behind the failure of the DMP to proceed. Specifically, APIA's submission to the Productivity Commission's Review of the National Access Regime contends that the gas transmission industry has indicated that it will only commit to significant new investment if the regulatory arrangements — including tariffs — are known in advance, and cites the failure of the DMP as an example of this.[27]

This argument relates to APIA's submission in 1999 to NGPAC on behalf of Epic Energy to amend the Code in order to remove the possibility of 'regulatory overlap' that could arise by the dual regulation of a new pipeline under both the Code and Part IIIA of the *Trade Practices Act 1974* (TPA). Essentially, Epic wished to offer the ACCC an access undertaking under the TPA rather than an Access Arrangement under the Code because it believed greater regulatory certainty for the DMP could be obtained under the TPA. Epic Energy submitted that unless greater regulatory certainty could be achieved in advance in relation to third party tariffs, terms and conditions, then it would have no alternative but to reduce the size of the pipeline to cater for foundation volumes only, *if* it was to construct the pipeline at all.

NGPAC considered Epic's arguments and agreed a recommendation to Ministers in 2001 the effect of which was that the owner or operator of a new pipeline not be required to submit an Access Arrangement under the Code where there is in force an access undertaking for that pipeline accepted by the ACCC under Part IIIA of the TPA. However NGPAC subsequently withdrew the recommendation to Ministers pending clarification of the implications of the decision by the Australian Competition Tribunal that the Eastern Gas Pipeline (EGP) should not be covered under the Code. Because of the EGP decision, it could not be assumed with any degree of certainty that an application for coverage of pipelines such as the DMP under the Code would necessarily be successful, and NGPAC subsequently deferred any decision on APIA's request to change the Code.[28] Industry similarly lost interest in the proposed Code change following the EGP decision. This lack of interest is evidenced by the fact that APT — who had a proposal for a competing pipeline with the DMP — played no role in lobbying for the proposed Code change, despite the fact that their pipeline would have been impacted by the regulatory framework in the same way as the DMP.

It is misleading to suggest that NGPAC's deferral of changes to the Code are responsible for the failure of the DMP to proceed. As noted above, other factors, in

[27] APIA (2000), *Response by APIA to the Issues Paper released by the Productivity Commission in Relation to the Review of Part IIIA of the TPA and Chapter 6 of the CPA*, pp 4-5.

[28] NGPAC (2001), *NGPAC Annual Report 2000–01*, pp 4-6.

particular the lack of certain gas supply from the Timor Sea are the critical factors. This view is evidenced in comments by the CEO of Australian Pipeline Trust, Jim McDonald, who did not identify access arrangements as a barrier to the project in a statement released to the Australian Stock Exchange in 2001:

> The first issue is the decision to bring gas to the shore at Darwin…Secondly, there has to be sufficient gas contracted in the southern and eastern states to justify the pipeline expenditure. That is a marketing exercise and it is progressing…The third issue involves land management along the route from Darwin to Moomba and into Queensland. That will take some time. The final issue is that our proposal involves maximum use of existing infrastructure and that includes negotiations with Santos and their joint venture partners as to how our new project will interface with their systems in the Cooper/Eromanga Basin.
>
> Jim McDonald, CEO APT, Open Briefing to the ASX: Australian Pipeline Trust, National Gas Pipeline, June 2001.

It is also worth noting that at no stage have Epic Energy ever submitted a proposed Access Arrangement in relation to the DMP — no regulatory arrangements have even been considered at this point. On this basis, we would hold that is presumptuous to suggest that as yet undeveloped regulatory arrangements could be responsible for the failure of the development to proceed to date, particularly given the many competitive market forces that have hindered the development so far.

PNG Project

Similar to the DMP, the proposed PNG pipeline project is dependent on a broader plan to develop a new gas resource for Australia. The history of the project to date shows that factors unrelated to the pipeline itself have led to a deferral of the PNG resource development, at least for the time being.

In May 1998, a joint venture of AGL and Petronas was appointed developer of a 2100km pipeline (at an estimated costs of $1.5b) to run PNG gas from the Australian border in Torres Strait to Townsville and Gladstone. The pipeline was to be capable of delivering 200PJ/pa, with construction planned to commence in 1999 and completion in mid to late 2001.

As with the DMP, the key driver of the PNG project's success would be the ability of proponents to secure customers for the required underpinning project load. AGL indicated that the initial load on the pipe was forecast to be 100 PJ/pa.

At an early stage in the project's development, AGL acknowledged in a statement to the ASX in 1998 that far from restricting the development of the project, the regulatory arrangements contained in the Code were allowing them to offer highly competitive tariffs to potential buyers and would assist in securing customers for the project:

> The tariffs are considerably below market expectations due to their innovative structure and will provide the catalyst for customers to commit to the project within the required timeframes…the market required that we provide competitively priced gas to Gladstone and AGL and Petronas have met that requirement…The tariff was the result of a competitive tendering process — the first under the National Third Party Access Code — and involved 26 players…including the Queensland Energy Regulator and the ACCC.
>
> AGL Statement to the ASX, 'Tariff Announced – Key Milestone in PNG to Gladstone Pipeline Project, 5 November, 1998.

In April 1999 gas reserves were confirmed when the original project sponsors (a Chevron lead Joint Venture) announced that they had signed a deal with Esso enabling the project to assure customers that adequate gas reserves were available from both the key fields in PNG to sustain a 30 yr project.[29] The sponsors noted at that time that:

> ... for the project to proceed, sound commercial terms need to be agreed between upstream suppliers and the potential customers from Gove through Cairns, Townsville and Gladstone, and even SE Qld.
>
> Oil Search ASX Announcement, 14 April 1999.

During 1999 a number of customers were signed up to the project, including Energex (130PJ/pa for 20 years) and Ergon (50PJ/pa for 20 years). In May 2000, the project received a further boost when the Queensland Government announced its 15 per cent Gas Scheme — this scheme will require electricity retailers and other liable parties to source at least 15 per cent of their electricity sold in Queensland from gas–fired generation from 1 January 2005.

However major issues remained unresolved in relation to the role of the PNG Government in the project, particularly in terms of their ownership of project infrastructure and their role in financing the project. This delay in finalising arrangements with the PNG Government meant that all of the conditional customers deals that had been signed during 1999 and 2000 expired.

Eventually an MOU with the PNG Government and project sponsors was signed in February 2002, and an agreement signed in June 2002. Critically however, it wasn't until this point — when the necessary legal framework was put in place to progress the development — that the project actually became a viable proposition from a upstream perspective.

Following the agreement with the PNG Government a number of new customers were signed to the project, including CS Energy (15PJ/pa for 20 years) and TXU (20-35PJ/pa for 20 years). However this demand was still well short of the

[29] Oil Search ASX Announcement, 14 April 1999.

minimum 100PJ/pa required for project viability, and the project sponsors consequently increased the scope of the project to supply customers from the Northern Territory and Eastern Australia. However, as noted below in the discussion on competing supply, demand from Eastern Australia is now being met by more competitive supply sources.

On 18 December 2002 AGL announced that they were withdrawing from the PNG deal in favour of arrangements with producers in Eastern Australia:

> The Australian Gas Light Company (AGL) has moved to secure its future gas requirements with a new portfolio of supply and transportation arrangements for the New South Wales, Victorian, South Australian, Queensland and ACT markets…The new gas supply and transportation portfolio, collectively worth around $4.5 billion, will secure the supply of up to 1,408 petajoules of gas over 15 years, through commercial arrangements with BHP-Billiton/Esso, the Santos-led Cooper Basin Producers and Origin Energy…AGL has today also advised the ExxonMobil led Papua New Guinea to Queensland producer group, that it is re-assessing its options for PNG gas.
>
> AGL ASX Announcement, 'AGL announces new gas supply portfolio', 18 December 2002.

Despite AGL's withdrawal, the PNG to Queensland pipeline project is very much still under active consideration. Although the Heads of Agreement between the PNG Gas project Owners expired on June 30 2003, ExxonMobil have very recently indicated that they are ready and willing to move the project to the next phase of development once sufficient customers are ready to make firm commitments for gas:

> We remain confident in the investment climate in PNG and believe that demand for competitively priced gas in Australia could provide a market opportunity for PNG gas.
>
> Mr. Rob Franklin, July 2003, ExxonMobil Gas and Power Marketing Company, Vice President, New Business Development, ExxonMobil Media Release, 'New Structure for PNG Gas'.

Similarly, Mr Robert Franklin, Vice president of ExxonMobil[30] emphasised in December 2002 that the project was likely to take a relatively long time to develop:

> I know that after six years many people are somewhat cynical of this Project but in fact it is a relatively short timeframe for a development of this sort.
>
> The sheer scale of the infrastructure development, the fact that it is a gas resource selling into a non-liquid market, the fact that it involves multiple parties through the gas delivery chain and transits both international and state borders makes it almost inevitable that it will take several years to develop.

[30] Mr Robert Franklin, Vice President, New Business Development ExxonMobil Gas Marketing, 'The PNG Gas Project: An Update', *Speech delivered to the PNG Mining and Petroleum Investment Conference*, Sydney, 3 December 2002.

Consistent with these statements, ExxonMobil are currently actively seeking customers for PNG gas — in July 2003, the company announced that from 2007 Energex will buy between 480PJ and 1,200 PJ of gas over 20 years. It will sell this gas to customers, including the Comalco Alumina Refinery.

Competing supply

The project histories for the DMP and PNG projects outlined above illustrate the importance of secured customer contracts in driving the viability of a major pipeline proposal. Prior to proceeding, major pipeline projects require some level of certainty around future demand for the gas that the pipelines will transport. In this context, one of the primary reasons that neither of the major pipelines planned from northern Australia in recent years have proceeded is simply that other — presumably more economic — gas supply options have become available to meet future demand.

It is the owners of demand — that is, retailers and larger end users such as power stations — that ultimately determine where the supply to meet their demand will come from. In this context, 'demanders' of gas can be expected to seek out the most competitively priced gas available at a given point in time, and new gas supplies will only become viable once more competitive supplies run short.

The DMP and PNG project proponents based their initial project plans on an assumption that future supply shortages in Eastern Australia would create excess demand and compel gas customers to seek gas supplies from the north. This expectation is likely to have been based on estimates of future demand for gas developed by the Australian Bureau of Agricultural Economics (ABARE) in 1997 & 1999 — at that point in time, ABARE were forecasting substantial demand increases in Eastern Australia over the period 2005-2010.[31] The expectation of future demand is also likely to have been driven in part by an assessment by the Northern resource owners of the extent of contracted East Australian gas supply.

[31] ABARE demand forecasts sourced from an Origin Energy presentation to the Macquarie Infrastructure Conference, May 2003, downloaded from http://www.originenergy.com.au/investor/files/macquarie.pdf

However ABARE have recently revisited the East Australian supply/demand balance and they now conclude that a physical gap in the East Australian balance will not open up until at least 2012-13[32] They concluded that eastern Australian supplies of gas are sufficient to meet projected demand up to and including the period 2011-12, and that this demand will be met by a combination of supplies from the Cooper–Eromanga, Otway, Bass and Gippsland basins in addition to increased coal seam methane production in Queensland and New South Wales (as detailed in Table 4.1 below).

The emergence of new supply sources in the south–eastern gas market has meant that there is no immediate need for *either* the DMP or the PNG pipeline at the current time. This is a market-driven outcome, and one that we would expect to see in a properly functioning competitive environment — the threat of natural gas supply from the Timor Sea or PNG served to accelerate the emergence of more competitive supplies to meet emerging demand. This proves that competitive forces are working and that end users and retailers can, and are, able to seek out the most competitive offers from producers to meet their demand for gas. While these new demand sources may not be able to meet increasing demand in the longer term, they have been able to fill the short term demand gap that both the DMP and the PNG projects were hoping to capture.

Table 4.1 Major supply sources committed since 2001

Field	Joint venture	Major sales contracts
New developments		
Yolla	Origin, AWE, Calenergy	260PJ ro Origin
Patricia/Baleen	OMV/Santos/Mitsubishi	60PJ to Energex
Ottway	Santos/Beach	36PJ to two retailers
Minerva	BHP/Santos	300PJ to International Power
Coal bed methane		
Camden stage 2	Sydney Gas	10PJ pa to AGL
Moranbah	CH4/BHP	290PJ to Enertrade
Scotia	Santos	120PJ to CS Energy
Anglo Creek	Anglo Coal/Mitsui Moura	78 PJ to Energex
Sales from existing developments		
Bass Strait JV	BHBP/Esso	In excess of 2000PJ to various
Cooper basin producers	See note	505PJ to AGL

Note: Volume is from both SA & Qld sections of the Cooper Basin JV SA section Santos 59.8%, Esso 20.2%, Origin 13.2%, Novus 4.75%& OMV 2.1% Old Section Santos 60.1%, Esso 23.2% & Origin 16.7% Source: BHPB.

[32] Dickson, A., and Noble, K., (2003), 'Eastern Australia's gas supply and demand balance', *APPEA Journal 2003* This estimate is conservative because it assumes that only 85PJ/pa of CBM production will be available in 2012-13 — ABARE estimates that Australia's total coal seam methane resources are estimated to be well in excess of 250,000 PJ.

Statements by the AGA support this view and indicate that lack of demand — and not the access arrangements contained in the Gas Code — was a key factor in the decision to delay bringing Timor gas onshore:

> The dash to gas has yet to happen…[The supply of gas from northern Australia to the south is] still an absolute essential, but it has been pushed back a few years.
>
> Bill Nagle, Executive Director of the AGA, The Age, 5/9/01, 'Timor gas plan prone to market not politics'

Jim McDonald — CEO of the Australian Pipeline Trust (a major stakeholder in the proposed PNG project) — confirmed that there was no short-term need for a pipeline from northern Australia to south eastern markets when he said very recently:

> While developments such as coal bed methane provided some hope, the industry must look towards building a major pipeline across the nation within the next 10 years…Without a major new gas supply source, the heavily populated south east of Australia will be short of competitively priced gas.
>
> Jim McDonald, CEO APT, 'Australia needs peak gas body to counter powerful coal lobby', *EnergyReview.Net*, 25 August 2003.

A statement by Mr McDonald to the ASX in August 2002 also supported the view that short term demand from south–east Australia was critical for the PNG project:

> Contracts in NSW, Victoria and SA are due for renewal from 2003 to 2006. If an alternative gas supply from PNG or Timor is to be established it must get the go ahead before new contracts are written. Sufficiently high volumes of gas will need to be secured for new gas supply infrastructure.
>
> Jim McDonald, CEO APT, *Open Briefing to the ASX: Australian Pipeline Trust MD on Growth Prospects*, 7 August 2002.

Mr McDonald subsequently confirmed that the emergence of new supply sources to meet demand in south–east Australia was the major factor in the delay of the PNG development in a statement to the ASX in April 2003:

> PNG gas has been delayed because the proponents are, as yet, unable to aggregate sufficient foundation volumes to underwrite the project…PNG to Queensland is still alive but its certainly been delayed by AGL's decision to take coal-bed methane from Surat Basin, and conventional gas from Gippsland. Exxon and their partners are still actively trying to bring together sufficient markets for the project to proceed, but it now seems that it will be delayed.[33]

Mr. Rob Franklin, Vice president of ExxonMobil agreed that demand for gas from Eastern Australia is critical to the success of the PNG project:

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[33] Jim McDonald, CEO APT, *Open Briefing to the ASX: Australian Pipeline Trust MD McDonald on Outlook*, April 2003.

> The project needs to have a significant volume of long term gas sales contracts in place before it can proceed…Our assessment of the market for PNG gas indicates there is more than sufficient demand for the project. However, that demand is spread out over time and trying to aggregate buyers around a certain time is proving difficult and time is running out…A number of existing contract terms expire in 2006–2007 allowing the Project to secure significant existing loads helping Project viability and financing…At this point our biggest remaining challenge is the commercially viable marketing of the gas. We do not currently have enough committed purchase volume to justify commencing Front End Engineering and Design (FEED) or to demonstrate a viable Project to the PNG Government, the banks, other buyers or the equity owners. Promises and future potential will not finance this Project[34].

It is notable that ABARE predicts that after 2012-13, supplies will fall short of projected demand, and a northern supply source will be required to balance projected eastern Australian gas demand. This suggests that at some point in the future, either the DMP or the PNG project is likely to become viable. In this context however, it is useful to note that only *one* of the DMP and PNG projects is likely to be viable in the medium term. Because the projects are both ultimately competing for the same gas customers in Eastern Australia — and because of the necessarily limited size of demand from this market, it is unlikely that both pipelines could go ahead in the near future. This suggests that due to competitive market conditions, one of the DMP or the PNG projects is likely to remain deferred for some time. This deferral cannot logically be attributed to regulatory uncertainty.

4.3 Victorian Distribution Network Extensions

Critics of the Regime have also cited the failure of the distribution network to expand further as an indicator that investment is being hindered by the current regulatory arrangements. In their submission to the COAG Energy Market Review the AGA contended that regulation was a key factor in the failure of a number of gas distribution network projects to proceed:

> The AGA has identified seven greenfields gas distribution projects with estimated project values in excess of $390 million serving nearly 500,000 potential gas consumers which have been deferred or shelved since 1999 due in part to the inadequacy of the current regulatory framework in addressing commercial risk and return issues in relation to greenfields gas infrastructure developments.
>
> AGA (2002), *Submission to the Energy Market Review: Response to Draft Report*, p 4.

To support their argument, the AGA has cited the following — mostly Victorian — distribution projects which have yet to proceed:

- Loddon-Murray Region (Vic) 2001;

34 Ibid.

- Barwon-Heads (Vic) 2000;
- Yarra Ranges (Vic) 1999;
- East Gippsland (Vic) 1999; and
- Central Ranges (NSW) 1999.

In our view, an understanding of the full background to these projects would suggest that the failure of these projects to proceed suggests that the profitability of the projects explains why they have not been commenced.

A study conducted for the Essential Services Commission (ESC) in Victoria concluded that very few of the potential new distribution projects to new areas were commercially viable, given the availability of substitute fuels.[35]

> The finding that over 80 per cent of potential reticulation is uneconomic at any price leads to the conclusion that any lack of activity in further extending the Victorian gas network is largely due to economics, rather than to market or regulatory failure.
>
> McLennan Magasanik Associates (2002), *Potential for Further Commercial Expansion of the Victorian Gas Network*, Report to the Essential Services Commission.

Out of the 37 projects considered by McLennan Magasanik Associates, only two were found to be commercially viable without also obtaining large customer load. Moreover, one of the projects identified by AGA as being impeded by the regulatory regime – Barwon Heads – was found to require additional large customer load of 129 TJ/annum – a massive load for an area that is mostly comprised of holiday houses and 'Sea Change' residents.

The failure of uncommercial projects to proceed cannot be seen as a failure of the Regime, as such projects could only occur if they were subsidised by existing customers. Rather, to the extent that governments consider that uncommercial extensions to new areas should be encouraged, then it is appropriate that this be funded as a community service obligation, and it is noted that this is exactly what the Victorian Government has commenced doing.[36]

Moreover, there are a number of examples of distribution pipeline projects that have gone ahead under the current regulatory regime. One project in particular — Cardinia Shire in Victoria — outlines how the flexibility contained in the Code is able to facilitate new investment (Box 4.1).

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[35] McLennan Magasanik Associates (2002), *Potential for Further Commercial Expansion of the Victorian Gas Network*, Report to the Essential Services Commission, p 30.

[36] Media Release, Bracks Government Details $70 million Gas Plan, 11 June 2003. It would be expected that AGA's members are now happy to emphasise the uncommercial nature of many of the gas distribution projects, given the potential for government subsidies.

Box 4.1 Cardinia Shire distribution project

The Cardinia project was commissioned by Status Networks (now Envestra) in 1999. The $2 million project provides reticulated natural gas to 2,300 customers located in the towns of Bunyip, Garfield, Nar Nar Goon and Tynong in the Cardinia Shire

Prior to construction, Status Networks submitted an application to charge extra (a surcharge) for gas distribution services in the Shire of Cardinia than is allowed in the Reference Tariff for existing Stratus customers. The surcharge was to reflect the greater distances involved in supplying gas to residents in the Cardinia area. Both the supplier and residents agreed that a surcharge was necessary for development to proceed.

In an illustration of the flexibility contained in the regulatory regime, the Victorian Regulator-General (now the Essential Services Commissioner) concluded that the surcharge would not amount to a material change to the existing Access Arrangement, and decided to waive the normal public consultation processes to expedite gas development in Cardinia. The Regulator–General subsequently approved the application by Stratus Networks Pty Ltd within a two month period.

Source: Boral Limited, News Release, 'Gas supplies turned on for $2 million natural gas transmission pipeline and distribution networks for Bunyip, Garfield, Tynong and Nar Nar Goon, 7 October 1999; Office of the Regulator General, Cardinia Shire webpage http://www.esc.vic.gov.au/gas355.html last accessed on 13 August 2003.

4.4 Flexibility in the Code

The criticisms of the Regime — and its administration by regulators — with respect to greenfields projects ignores the flexibility already contained in the Regime to deal with these projects, and the substantial efforts that regulators have made to demonstrate how the Regime can accommodate — and even promote — these projects.

In this regard, this section will examine efforts by the ACCC and other regulators to promote greenfields investments. We will then discuss regulatory activities undertaken in recent years that represent the innovative use of regulation to promote efficient investment outcomes. Specifically:

- the ACCC's decision in relation to the Central West Pipeline (CWP), the first greenfields decision taken under the Code;
- efforts by the ESC in Victoria to promote the roll-out of distribution networks in Victoria; and
- the flexibility of the Regime in excluding pipelines from the regulatory net when appropriate.

Efforts by regulators to promote greenfields investments

ACCC Guidelines for Greenfields Investments

The ACCC has taken a number of steps to reduce uncertainty for potential pipeline investors, and increase the flexibility and clarity of the regulatory process associated with gas pipelines.

Most significantly, in June 2002 the ACCC released its *Draft Greenfields Guideline for Natural Gas Transmission Pipelines*[37]. This guideline aims to:

- address perceptions of regulatory risk with regard to the application of the regulatory framework and the ACCC's approach to the regulation of greenfields projects;
- demonstrate the flexibility of the regulatory framework and the various approaches available for the structure of an access arrangement or access undertaking;
- indicate the ACCC's preferred methods for dealing with project specific risks; and
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

The ACCC's Greenfields Guideline is not prescriptive in how the ACCC would deal with greenfields projects, and it specifically invited project proponents to propose arrangements that best suited their interests. However, the Guidelines do provide guidance on some of the approaches to addressing the unique characteristics of greenfields developments within the Code, as well as pointing out some of the risk-mitigation measures already contained in the Code. These approaches or measures included the following:

- noted that the Code already requires that the actual cost be used, which would include funds used during construction (capitalised at the WACC) and other financing costs incurred during construction, and is not subject to a prudence test (thus resulting in much of the construction risk being passed onto users);
- foreshadowed an approach to modelling the distribution of possible expenditure and demand outcomes to ensure that forecasts represent expected values rather than most likely values;
- noted that depreciation could be structured to permit losses in the early years to be carried forward (and capitalised at the WACC) to when demand is higher, thus reducing the risk associated with the timing of the new demand;
- noted that a number of approaches could be used to ensure that opportunity remains for the service provider to retain higher than expected returns (and so balance off the potential for lower than expected returns), including:
    - using longer regulatory periods, possibly combined with a symmetric 'earnings sharing mechanism' (i.e. which shares any upside or downside beyond a band between the service provider and users according to a preset formula); or

[37] ACCC (2002), *Draft Greenfields Guideline for Natural Gas Transmission Pipelines*.

- using a deemed forecast of demand to set tariffs – in particular, to use the original (average) demand forecast to set tariffs over a number of periods, so that if actual demand is higher than the original forecast, the service provider would retain this benefit; and

- noted that service providers have an option (unavailable to regulators) to seek an earlier review of reference tariffs, and that elements of a reference tariff policy can be 'locked in' through the fixed principle mechanism permitted by sections 8.47-8.48.

The ACCC's decision on the Central West Pipeline provides a practical demonstration of the application of these principles, which is discussed in Box 4.2.

Box 4.2 Central West Pipeline (NSW)

The regulator's decision in relation to the Central West Pipeline (CWP) provides a practical example of the flexibility of the current Regime in dealing with greenfields transmission pipelines. In particular, the decision illustrates the use of a flexible regulatory term and innovative depreciation schedules and tariff design as recommended in the ACCC's Guideline for Greenfields Investments described above.

The CWP extends from Marsden to Dubbo in NSW and links to the Moomba to Sydney pipeline (MSP). The CWP is operated by Agility and the pipeline became operational in 1998.

The CWP had few customers at the time the initial Access Arrangement was submitted to the ACCC. A major issue in the Access Arrangement for the CWP was therefore the determination of the appropriate rate of return for a new pipeline, taking into consideration risks specific to greenfields pipelines without substantial foundation customers or contracts.

The ACCC released its final decision on the proposed access arrangement for the CWP in June 2000 — this was the ACCC's first decision under the Code in relation to a greenfields pipeline. Key components of that decision that illustrate the flexibility of the Code in responding to greenfields investments were:

- *ten year arrangement* — specific risks identified by AGLP were acknowledged and addressed through a mechanism based on an extended access arrangement period of up to 10 years' duration in conjunction with explicit discretion on the part of AGLP to submit early revisions to the access arrangement. AGLP will have the ability to retain the benefits of any out-performance for ten years and potentially earn a rate of return substantially higher than is suggested by the ex ante return on equity if it exceeds forecast volumes or reduces its forecast costs;
- *recognition of early loses* — this regulatory framework allows AGLP to capitalise early losses so that they can be recovered once demand grows. This significantly mitigates the risks associated with demand uncertainty; and
- *no capacity charge* — in order to accommodate a lack of foundation customers, there is no fixed reservation charge for capacity. The CWP Reference Tariff is charged based only on actual throughput, rather than capacity.

In response to the ACCC's decision, the industry complained that the ACCC failed to adequately recognise the difference between the risks of greenfields investments and the risks of investments to service mature capital cities markets. However, in a subsequent statement the CEO of the APT said of the decision:

> "The Central West Pipeline in New South Wales is one greenfields project in which the ACCC recognised a different risk profile from that of mature pipelines. This gives us some confidence that new pipelines will be treated in a way which recognises and rewards the risk taker."
>
> *Jim McDonald, CEO of APT, Statement to ASX 9/3/2001, 'Open briefing: APT CEO on Profit'.*

The APT website also acknowledges that:

> "As a new or greenfields pipeline, the CWP Reference Tariff was designed to allow for penetration of gas into a new and growing market"

Source: ACCC website: www.accc.gov.au; APT website: www.pipelinetrust.com.au

As a companion to the greenfields guideline, the ACCC and National Competition Council (NCC) produced a joint publication, the Regional Development of Natural Gas Transmission Pipelines (Regional Guide) in late 2002 to facilitate investment in greenfields gas pipelines in regional areas[38]. The regional guidelines are for regional councils considering the development of natural gas transmission pipeline infrastructure projects to their communities. Box 4.3 sets out the ACCC's views on the various provisions in the Code that provide certainty for investors.

[38] ACCC and NCC (2002), *Regional Development of Natural Gas Transmission Pipelines*.

Box 4.3 Provisions in the Code which facilitate regulatory certainty

Relevant section of the Code		Implication
• Section 2:	Due process	Ensures a fair hearing, rights of appeal etc for service providers.
• Section 2.21:	Timely regulatory rulings	Guarantees an access arrangement decision within 6 months and ensures the service provider is not left in limbo.
• Section 2.24:	Protecting interests	The relevant regulator must balance different interests (service providers, users and the community) appropriately.
• Section 2.50: arrgts	Allowance for negotiated	Gives service providers the flexibility to negotiate a variety of pricing structures with customers.
• Section 3.16(b):	Pricing expansions	Gives service providers certainty over pricing arrangements for future investments.
• Section 3.18/19: arrangement duration	Access	Access arrangement can be of any agreed duration.
• Section 6: shippers	Foundation	Allows contracts held by 'foundation shippers' to proceed without interference.
• Section 6:	Dispute resolution	Provides service providers with confidence that disputes will be adjudicated according to a predetermined process.
• Section 6.15	Guidance for the arbitrator	Requires the arbitrator to consider the legitimate business interests of the service provider.
• Section 6.18:	Restrictions on decisions	Limits the types of decisions an arbitrator can make.
• Section 8:	Reference tariffs	Specifies the methods for setting tariffs, the costs that will be examined and the processes that will be used to do this. This ensures a service provider has a fair opportunity to earn revenues.
• Section 8.3:	Form of regulation	Allows the service provider to chose between two alternatives for setting prices: a 'price path' or a 'cost of service' approach. This allows a service provider to choose between a 'hands off' regulatory arrangement and certainty of cost recovery.
• Section 8.4:	Total revenue	Provides three alternative methodologies for calculating the revenue target.
• Section 8.12: New	Initial capital base, pipelines	Protects the service provider from downward revaluations by ensuring that the initial capital base will be valued by the actual costs of the asset.
• Section 8.14: base	Rolling the asset forward	Ensures that when establishing a new access arrangement, the regulator cannot apply an alternative methodology that would change the asset base.
• Section 8.16:	Pricing capacity extensions	Providers certainty to service providers about the pricing arrangements for expansions to capacity.
• Section 8.19 investment	Speculative	Allows for the creation of a speculative investment fund that can be later put into the capital base when these assets are called for.
• Section 8.30/31:	Rate of return	Clearly specifies the methodology by which investors recover costs **on** an investment.
• Section 8.32/33:	Depreciation	Sets out rules for the mechanism by which pipeline investors recover the costs **of** an investment.
• Section 8.43	Discount practices	Allows, under certain circumstances, the service provider to extend discounts to price-sensitive customers and recovers other wise forgone revenues from tis other customers.
• Section 8.47/48:	Fixed principles	Provide a means of establishing regulatory certainty across access arrangement periods.

Source: ACCC (2002), Draft Greenfields Guideline for Natural Gas Transmission Pipelines, pp 64-67.

The publication of both of these guidelines by the ACCC are recognition that sometimes the commercial viability of transmission proposals will be marginal at best, regardless of whether the pipeline is regulated or not. The guidelines aim to ensure that stakeholders are aware that where a project may be considered marginal only in the near term, the regulatory framework provides some flexibility to facilitate an otherwise viable proposition. Certain aspects of the guidelines also reassure potential investors that regulatory decisions will be predictable and stable over time.

Both sets of guidelines are relatively new and their effectiveness in improving flexibility and reducing any industry uncertainty is yet to be tested. Nevertheless, they represent a significant attempt by the regulator to remove uncertainty in the industry, and further facilitate greenfields investment in the gas sector.

The ESC and distribution pipelines in Victoria

Similarly, the Victorian Essential Services Commission has explained how the Code can accommodate some of the specific features of greenfields gas distribution projects, and even facilitate the development of such projects. In its recent review of the access arrangements for the Victorian gas distributors, the ESC accepted arrangements for treating greenfields projects, with the following main features:

- the distributors would have discretion as to whether the project would be covered (and included in the distributor's existing access arrangement);
- if covered (and thus included within the existing access arrangement), the agreed regulatory treatment was as follows:
  - the costs and revenues associated with the project would be quarantined from the incentive arrangements applying to the distributors existing business, so that the distributors would not be inadvertently penalised (through the incentive arrangements) for undertaking a different scope of activities;
  - there would be the ability to levy an additional charge for the users of the greenfields project, and costs not recovered in this way would be included in the distributor's regulatory asset base at the next review; and
  - the losses borne by the distributors as a result of undertaking the project within a regulatory period would be carried forward (together with financing costs) and also included within the distributor's regulatory asset base; and
- the distributors would retain the sole discretion as to whether a project would proceed.

The ESC noted that the coverage of such projects and inclusion within an existing access arrangement may improve their feasibility, through the ability to pool the risk associated with a number of such projects.

> … the practical implication of including the expenditure in the regulatory asset base is that the distributor's ability to recover this expenditure is dependent only upon the viability of its whole distribution network, not the viability of the new project in

> isolation. The Commission would expect that some new projects might turn out to be more profitable than expected, whereas others may turn out to be less profitable than expected. Hence, on average, rolling-in these projects would not be expected to affect the prices charged to existing customers. However, reducing the distributors' earnings uncertainty by being able to 'pool' all of their projects should improve the prospects of extending gas networks to new areas.
>
> ESC (2003), Gas Access Arrangement Review: Final Decision, October 2002, p.53.

Regarding the distributors sole discretion as to whether to proceed with such projects, the ESC noted that this statement just reflects a service provider's their legal rights under the Code. However — and possibly reflecting an earlier experience with one of the distributors — the ESC noted that it expected the distributors to exercise this power in a responsible and transparent manner:

> However, it also considers that it is not in the interests of any party for community expectations to be built up about the prospect of receiving gas, and to then have a project vetoed by the distributor. To this end, the Commission would expect distributors to undertake thorough economic evaluations of prospective extensions to unreticulated towns, as set out in their proposed Revisions, before approaching the Commission to discuss the regulatory treatment of such projects. It would also expect the distributors to consult with affected communities in developing such proposals. Lastly, the Commission would expect the distributors to exercise their discretion to veto a project in a responsible and transparent manner, which should include full disclosure of the reasons for not proceeding with such a project, particularly if this occurs after community expectations have been built up.
>
> ESC (2003), Gas Access Arrangement Review: Final Decision, October 2002, p.56.

Code coverage

The above discussion focuses on instances in which the coverage of new pipelines by the regulatory provisions contained in the Code has been able to provide investors with improved regulatory certainty and flexibility. However the ability of the Regime to *exclude* pipelines from coverage under the Code where it is not deemed necessary is also an important indicator of the overall efficacy and appropriateness of the current regulatory framework.

The National Competition Council (NCC) are responsible for providing advise to relevant Minister on whether or not particular pipelines should be covered by the Code. The four coverage criteria used by the NCC in determining whether a pipeline should be covered are:

- Criterion (a): that access (or increased access) to services provided by means of the pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the pipeline;

- Criterion (b): that it would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline;
- Criterion (c): that access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety; and
- Criterion (d): that access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest.

The NCC must be affirmatively satisfied that **all four** of these criteria are met before it can recommend coverage. If the NCC is not satisfied that even one of the four criteria is met it must recommend that the Pipeline not be covered.

The coverage test used by the NCC ensures that the Code operates only as 'backstop' and is used only when there is evidence of monopoly power, or where regulation is needed to promote competition in upstream or downstream industries. Regulation of access arrangements for gas pipelines where there are no prospects for either monopoly power or reduced competition is therefore deemed to be unnecessary under the current system. This intent of the Code is demonstrated by the fact that since the commencement of the Code in 1997, 16 of the then 47 regulated pipelines are now no longer regulated.

The fact that many of the major pipelines built recently are not covered by the Code clearly demonstrates the fact that the Regime is not acting to inhibit investment levels in the industry. It is our view that the construction of major new pipelines from outside the Code provides further evidence that the regulatory regime as it currently stands is effective. This section will discuss two case studies in this regard:

- the Eastern Gas Pipeline (EGP) in NSW; and
- the roll-out of gas distribution pipelines in Mildura.

These examples prove that the Code is only implemented in cases where it is deemed necessary, and that investors will not face regulatory hurdles unless there are clear reasons for imposing these.

Eastern Gas Pipeline

The EGP provides a useful example of an instance where the regulatory regime operated effectively to leave a new pipeline outside the regulatory framework. The Australian Competition Tribunal reviewed a decision by the Minister for Industry, Science and Resources to cover the EGP pursuant to the Code, and decided that the pipeline should not be covered. NCPAC stated that the EGP decision illustrates the

importance of the coverage test, and in particular the requirements in the Code that coverage is only available:

- in relation to the services provided by infrastructure having the characteristics of a natural monopoly; and
- where regulation of that infrastructure would promote competition in a market for services or in another (upstream or downstream) market to a level greater than would occur without regulation[39].

The EGP decision suggests that in some circumstances providing regulated access to a transmission pipeline will not promote competition in upstream or downstream markets even though it may be the only pipeline covering a particular route. As noted earlier, as a consequence of the EGP decision, the concerns and consequent Code change proposals raised by Epic Energy and APIA in the context of the DMP relating to regulatory certainty and overlap appear to have become less urgent, as it cannot be assumed with any degree of certainty that an application for coverage of pipelines such as the DMP under the Code would necessarily be successful.

Mildura, Victoria

The Mildura distribution system project in Victoria provides an example of where revocation of Code coverage has been used effectively to minimise the impact of regulation on investment decisions.[40]

In 1999 Boral Energy (now Origin Energy/Envestra) won a competitive bid from the Victorian Government to construct a $30 million project involving 190 kilometres of transmission pipeline and 160 kilometres of distribution pipeline. The pipeline was covered under the Gas Code through a competitive tender process approved by the Office of the Regulator-General (now the Essential Services Commission).

The Mildura distribution system now serves 890 customers in the area of the city of Mildura and the nearby townships of Merbein, Red Cliffs and Irymple.

In accordance with the Gas Code, Envestra applied to revoke coverage of the Mildura distribution system with the National Competition Council in October 2002. Coverage of the Mildura distribution system was revoked in December 2002

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39 NGPAC (2001), *NGPAC Annual Report 2001*.

40 Mildura project information sourced from National Competition Council website "Mildura distribution system (Victoria): application for revocation from Envestra Limited" http://www.ncc.gov.au, last accessed 13 August 2003; Envestra Media Release, 'Prospectus for a 1 for 4 non-renounceable rights offer of 87 million new securities at an issue price of $0.88 per new security', 22 July 1999.

on the basis that the coverage was unlikely to promote downstream natural gas competition as the City of Mildura was too small.

Moomba to Sydney pipeline

It is also worth briefly considering in this context the process currently underway in relation to the coverage of the Moomba to Sydney pipeline (MSP) by the Code. APT have applied to the NCC to have coverage of the pipeline revoked and a decision has yet to be made by the NCC. The process being undertaken by the NCC has been going for a number of years — this extended time frame is not, in our view, unexpected given to the complexity of the issues that both the NCC and public submissions have identified. Regardless of which way the decision comes down, BHPB are confident that due process will have been followed and all the coverage tests will have been fully considered.

4.5 Observations on Greenfields Projects and Implications for Other Projects

Greenfields Projects

In the previous sections, we have demonstrated that the 'concrete' examples of the Regime's failings with respect to 'greenfields' projects lose much of their substance once the full background to the example is understood. Regulation is just one of the factors that affects the viability of greenfields projects, and for these projects, arguably it was not even a material factor.

BHPB has been involved in the debate about the capacity of the Code to accommodate the specific features of greenfields projects, including as a member of the roundtable discussion the Commission convened as part of its development of its draft Greenfields Guidelines.[41] BHPB is also a foundation user on a number of pipelines – including the Eastern Gas Pipeline – and has developed a number of pipelines in the past, and so has an intimate knowledge of the development process of pipelines and the role of foundation users in the process.

In our view, the Code provides the flexibility to address the specific features of greenfields projects, and would not present a barrier to efficient projects proceeding. As discussed above, the ACCC has described the flexibility that exists in the Code and indicated – as well as demonstrated – a preparedness to make full use of this flexibility. In response, the only specific problems with the Code that the industry

[41] GG, p.5.

has identified are of the nature of technical shortcomings – such as confirming that regulators have the ability to approve an access arrangement advance of a pipeline being built. BHPB would support amendments of this nature. BHPB would also support a refinement of the competitive tendering provisions of the Code. Competitive tendering – by using 'competition for the market' rather than the regulator to set reference tariffs – is a very effective means of facilitating the development of new projects and simultaneously deriving an acceptable reference tariff for all parties. We note that the PNG pipeline went through the Code's competitive tendering process, had a tariff approved, and the outcome was considered reasonable by all parties involved. However, BHPB agrees that the current provisions are cumbersome and could be refined. Subject to these points, BHPB considers that the onus now should be on service providers to demonstrate how they consider that the flexibility inherent in the Code should be applied in the context of greenfields projects.

BHPB would also draw the Commission's attention to the submissions about greenfields projects that it made about the role of foundation contracts to the Commission's Part IIIA Review. Foundation contracts have been an important feature of gas industry developments to date, and will remain so in the future. Foundation contracts are an efficient means of allocating the risk associated with long-lived and specific projects between the various parties, and are a feature of unregulated as well as regulated markets. It is imperative that any investigation of the treatment of greenfields projects understand the role of such agreements. We consider that, once such risk-sharing agreements are taken into account, much of the risk associated with matters like 'regulatory truncation' are at best exaggerated by the pipeline industry, and in many cases are just illusory.

On this matter, we note that a new argument of the pipeline industry is that the 'most favoured nation' clauses that are common in foundation contracts encourage the undersizing of pipelines, as the service provider would be concerned that subsequent access by third parties at low regulated prices would flow through to foundation users. BHPB does not consider this argument to have any merit. Both the service provider and users benefit from third party usage, and so benefit from the construction of an optimally sized pipeline. Accordingly, the claim that the parties will permit such an inefficiency to occur (i.e. an undersized pipeline) by adhering to some form of 'standard practice' ignores the ability and incentive for service providers and foundation users to negotiate arrangements that serve their joint interest, in the context of a particular project. In any event transmission pipelines can be expanded in a number of cost effective ways as clearly stated by the CEO of APT:

> We can and will expand the capacity of several of our pipelines. We can do that in one of three cost effective ways – by looping, or by adding compression or by adding spur lines.

Jim McDonald CEO APT Open Briefing ASX 09 March 2001.

Other Projects

However, BHPB's main concern with the 'greenfields project' debate is that the extension by the pipeline industry and its associations of the spectre of 'chilling' of investment far beyond 'greenfields' projects.

The majority of the assets that are regulated under the Code serve well-established markets and are in a position to exercise substantial market power. Indeed, as discussed above, the Code can only cover pipelines that have substantial market power — pipelines that can demonstrate otherwise can have their coverage revoked, and unregulated pipelines would not pass the test for coverage. For these projects, the special features of 'greenfields projects' do not exist. Demand and expenditure requirements are predicable, prices can always be set to recover the costs incurred in providing the service (that is, there is no threat of 'regulatory truncation') and most importantly, the risk borne by the service providers is very low. Accordingly, should the Commission consider recommendations for changes to the Code to address greenfields projects, there is no basis on which to extend such changes to all pipelines regulated under the Code.

As noted in chapter 2, the pipeline industry associations have also made references to the impact on firms' balance sheets and the valuations of their companies. BHPB consider that the Commission should be cautions with the interpretation that is placed upon such claims.

As set out in detail in sections 2.3 and 3.2, over the last 10 years a vast number of gas assets have been traded, both as part of privatisations by governments and as trade sales. A similar observation could be made about assets in the electricity industry in Australia, were governments have received tens of billions of dollars of proceeds from privatised assets, and many of these assets have already been on-sold to another buyer. The prices at which many of these transactions took place shocked many in the industry at the time — and indeed, was questioned in the press and informed commentators at the time. Moreover, Australia was not alone in this trend — both the volume of asset sales and the fervour with which prices were bid up was a world wide trend.

Only one gas regulator has assessed the prudence of the prices paid for gas assets during this period, the Independent Gas Access Regulator (WA), who was directed to do so by the Court. Nor surprisingly, the regulator reached the same conclusion as that in the popular press at the time of the sale of the Dampier to Bunbury Pipeline:

> 254 Firstly, the Court referred to the price paid for the DBNGP according to standards of reasonable commercial judgment as to value. In this regard, the evidence before me suggests that the value of Epic Energy's bid for the DBNGP was very sensitive to an assumption made by Epic Energy's advisors as to the rate of return on assets that would be approved by a regulator for the purposes of approving a tariff under the Code. For the reasons set out above, I find that in deriving the expected value of the DBNGP and the purchase price, no proper consideration was given to substantial downside risk in the assumption made as to the rate of return that may be approved by a regulator. Therefore the price did not reflect reasonable commercial judgement. A prudent and objective assessment of a future independent regulator's likely position on the rate of return, based upon information available at the time, should have identified this risk and reflected this risk by assuming a lower regulatory rate of return in assessing the value of the pipeline. As a consequence, the price paid for the pipeline by Epic Energy exceeded a reasonable market value for the asset.

Clearly, it is unreasonable for customers to bear the costs associated with the excessive exuberance of the purchasers of these assets, and it is also unwise for any regulatory regime to deliver this result. One of the strengths of the 'incentive regime' that Australian regulators apply when assessing reference tariffs is that service providers have freedom over their financing decisions – that is, they can seek whatever proportion and type of debt financing they wish, pay whatever level of dividends they consider appropriate and pay whatever they like for new assets. However, a necessary requirement for all of this freedom is that service providers take responsibility for their decision – that is, benefit from decisions that turn out to be good, but also bear the costs associated with decisions that turn out to be bad. The consequence of not exposing service providers to the consequences of their financing decisions is that perverse incentives over financing will be created, and prices will rise for customers (i.e. what in economic terms is 'moral hazard').

The report by The Allen Consulting Group discusses more appropriate metrics for assessing the stance of regulators. In that report, it is noted that a comparison of the market value of a regulated entity with its regulatory value provides the best overall test of whether regulators are providing returns on regulated projects that are insufficient, or whether regulators could be characterised as generous. Importantly, this test is based upon objective market evidence, and reflects all of the factors that may lead to service providers being over or under-compensated for the services provided, that is, reflecting the accuracy of a regulator's forecasts of future expenditure requirements and demand, any risk of 'regulatory truncation' and the return on the regulated assets that is factored into the reference tariffs.

The findings of this analysis provide a very strong refutation of the assertion that regulators have failed to understand the risk associated with regulated businesses, or that they have selected cost of capital estimates that are that the low end of the feasible range, or that regulators have set prices that are too low for any other

reason. Rather, the study provides direct and objective evidence that regulators consistently have erred in favour of regulated companies, and that no barrier to investment in these activities can be claimed to exist.

4.6 Conclusions

The outcomes generated by the gas industry during the period of the current regulatory regime illustrate that — contrary to views put forward by the pipeline industry — the regulation of gas pipelines in Australia in recent years has been conducive to efficient levels of capital investment in the industry.

Major pipeline proposals that have not yet gone ahead — such as the DMP and the PNG projects — have been stalled for a variety of non–regulatory reasons, most obviously the failure of project proponents to bring gas from the Timor Sea and PNG onshore, and the increase in alternative sources of supply in south east Australia. Rather than providing an argument against the Code, this scenarios provides a working example of an instance where the competitive environment facilitated by current regulatory arrangements has resulted in efficient market-generated supply and demand outcomes.

However, while it is possible that the gas demand in south eastern Australia eventually will justify a pipeline to either – and, eventually possibly both – of the reserves in the Timor Sea or PNG, the gas demand does not exist to justify either project at present. As noted, the unfilled demand that was the result of a number of contracts expiring over the next few years has been met with supplies closer to the sources of demand, and a significant portion of which has been met from new gas fields. Given the high cost of a pipeline to connect the Timor Sea or PNG gas reserves to the south east Australian gas markets, it is the most economically efficient outcome to defer such investments where possible, and to serve gas demand through the new and existing gas fields that are close or already connected to the sources of demand for as long as possible.

That said, the existence of the Timor Sea and PNG reserves – and the potential for these reserves to be supplied to the Eastern Australian gas market has already encouraged the accelerated development of a number of new gas fields, and has increased the degree of rivalry in the supply of gas from all fields. Thus, far from the deferral of either project for now being a concern with the Regime, the ability for such projects to increase the competitive discipline on participants in the gas supply chain should be seen as a success. BHPB notes that the gas reserves both the Timor Sea and PNG are very large, and the deferral of these pipeline projects just mean that the gas reserves that otherwise would have been sold into the south east market will remain underground for the time being. However, there is nothing in the

experience of these projects to date to suggest that either or both projects will not be developed, when it would be efficient to do so.

The evidence also indicates that the Code and the regulators that administer it have often responded in a flexible way to the needs of greenfields investors. The CWP in NSW provides a clear example of an instance where regulators made use of innovative regulatory arrangements — such as an extended access arrangement period and specific recognition of early losses — to reach an outcome that industry representatives described as recognising and rewarding risk taking investors. Similarly, the recent roll-out of distribution pipeline projects in Victoria illustrates the use of flexible regulatory arrangements, and where these projects have not gone ahead, commercial considerations are most likely the driver. The many pipelines that remain outside the regulatory net confirm the ability of the current Regime to effectively apply appropriate regulatory mechanisms only when appropriate.

PART 3

OPPORTUNITIES FOR IMPROVEMENT

Chapter Five

Form of Regulation and Ring Fencing

5.1 Form of Regulation

The section provides BHPB's views on what it considers are two key components of the pricing elements of the Code, which are:

- the use of cost based pricing, and — within this, the principle that the regulatory asset base be 'rolled-forward'[42] from one price review to the next rather than reset according to a new estimate of some value (such as a new estimate of a depreciated optimised replacement cost value) at future price reviews; and
- the setting of up-front reference tariffs at a price review, rather than case-by-case arbitrations.

These issues are discussed in turn below.

Cost Based Pricing

BHPB notes that the submission it has commissioned from The Allen Consulting Group addresses in some detail the rationale for cost based pricing for natural monopoly downstream gas pipelines, as well as clarifying the merits and disadvantages associated with the 'building block approach' and the virtues of the Code's approach to the revaluation of assets over time. The Commission is directed to that submission for more detail economic principles underpinning the discussion below.

Rationale for Cost Based Pricing

In BHPB's view, the rationale for setting access prices with reference to cost is obvious from one of the main objectives behind regulated access charges, which is

42 The term 'rolled-forward' implies that the regulatory asset base is updated from one review to the next by commencing with the opening regulatory asset base at the preceding regulatory period and adding in actual capital expenditure and deducting depreciation and disposals. Values would also be escalated for inflation where a return WACC had been used to set the previous price path.

to set access charges at a level that will maximise upstream and downstream activity, while also providing sufficient incentive for continued investment in the regulated industry over the long term. As investors in any new project in any industry look to the returns expected from their actual outlays (ie actual cost) when deciding to proceed with the project, it is impossible to resolve the conflict between maximising allocative and dynamic efficiency in the related activities and ensuring the regulated services continue to be provided efficiently over time without reference to cost.

On this matter, BHPB notes that the Commission reached the same view in its Part IIIA Review:[43]

> …the Commission remains unconvinced that prices can be fully decoupled from costs.

That is, the Commission accepted that there should be a relationship between regulated prices and costs.

BHPB also agrees with the Commission's view that any attempt to set access charges without reference to cost was likely to be asymmetrically biased in favour of the regulated entities (with detrimental implications for related markets):[44]

> Indeed, the Commission considers that it is naïve to imagine in the situation … — whereby a productivity-based approach drove prices below a particular facility's costs — that the facility owner would not appeal to have the outcome changed on the basis of cost information.

Where prices had not been set with reference to costs, users would have no basis upon which to appeal against excessive charges for access.

In its Part IIIA Report, the Commission considered that the real debate was not about whether access prices would be set with reference to costs, but in effect, how cost should be measured. In particular, the Commission noted that the real issue was the extent to which the existing building block approach can be improved upon.[45] The Commission expressed a number of concerns with the building block approach, and recommended that more be undertaken on "productivity measurement and benchmarking techniques".[46]

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43 Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra, p. 349.

44 Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra, p. 349.

45 Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra, p. 350.

46 Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra, p. 351.

BHPB notes the conclusions of The Allen Consulting Group's report that the Commission's consideration of this issue in its Part IIIA Review appeared to lack structure, and that much of the criticism of the building block approach was misguided. This matter is discussed next.

Building Block Approach and Incentive Regulation

When considering how to set regulated charges that reflect cost but which also provide incentives for productive efficiency, the main decisions are:

- whether prices set initially (and reset periodically) with reference to actual cost or some form of predicted cost;
- how the rate of change of prices is set between those price reviews (the X factor); and
- the length of time between price reviews.

With respect to the first of these decisions — whether initial prices should reflect some form of predicted or actual cost — BHPB considers that the latter (actual cost) is the only approach that is likely to meet any sound principles for regulation. BHPB has no faith in the ability for econometric (benchmarking) methods to provide sufficiently accurate predictions of the efficient cost of undertaking an activity to provide a robust basis for setting access charges. Moreover, it is noted that the majority of the participants in the transportation elements of the Australian gas industry agree with this proposition:[47]

> Most owners of infrastructure have little or no confidence in benchmarking approaches to efficient cost determination for use in setting regulated access prices. Vogelsang explains why this is so. He observes that regulation which makes the prices a utility can charge dependent on the performance of other firms or on some efficient benchmark "is risky for a utility to the extent that its costs differ from the yardstick by virtue of such factors as geology, climate, population density, local wage rates, taxes, or the like". Experts, particularly those with only limited exposure to the firm at issue, will often lack the detailed, firm-specific, knowledge needed to correct for these differences.
>
> In addition, there is a perception that experts may be influenced by what they perceive to be the agendas of their principals. If the principal is the owner, then experts are more likely (or are perceived as being more likely) to bend their findings to favour the owner. If the principal is the regulator, then experts are likely (or are perceived as being likely) to bend their findings against the owner.
>
> Overall, we submit that the search for efficient operational costs by analytical means is almost certain to fail in practice given the information uncertainty facing regulators. It is, in other words, ultimately likely to prove futile and socially harmful. Additionally, it is our view that that search should be unnecessary in the presence of a properly constructed regime based on incentive regulation.

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[47] Network Economics Consulting Group, *Joint Industry Submission on the Productivity Commission's Review of the National Access Regime*, June 2001, pp. 37.

> The theoretical basis of incentive based regulation is that efficient costs will be revealed through the operation of properly structured incentives — it is not necessary to seek to determine those costs by other means such as regulatory inquiry.

BHPB's agrees with these criticisms of the use of econometric (benchmarking) methods for setting regulated charges, and with the recommendation — which is to use well-designed incentive regulation (ie a price cap) to provide regulated entities with an incentive to be efficient, and to use these efficient (actual) costs when periodically reviewing regulated charges. BHPB's own concern derives from the inherent asymmetry of information associated with cost-prediction models: any regulated entity accused of being inefficient inevitably will produce information to 'prove' that an important explanatory variable has been excluded from the analysis — which is a debate on matters on which the regulated entities inevitably have the upper hand.

Given the apparent consensus on this matter, the option of using 'predicted efficient costs' to set access charges should be ruled out by the Commission.

Regarding the setting of the X factor in the price cap between reviews, it is noted that two options exist, which are:

- to forecasts operating and capital expenditure and demand (including any assumptions about productivity gains), and to set the rate of change of prices such that tariff revenue and the revenue benchmarks are aligned; or
- to set the X factor at a level that is determined exogenously (for example, according to an estimate of the long term trend in total factor productivity).

The former methodology corresponds to what is often referred to as the 'building block' approach, whereas the latter is what the Commission appears to be referring to in the Part IIIA Review.

BHPB notes the important conclusions in this matter in The Allen Consulting Group's report, which included the following:

- Both approaches involve resetting prices in line with cost at periodic reviews.
- There is unlikely to be a difference in the incentive qualities of the two approaches, as it is the decoupling of prices from costs for a period that provides the incentive for regulated entities to be productively efficient. Irrespective of how the rate of change in prices over the period was derived, the expected payoff from reducing charges should be the same.
- The comments that the use of the building block approach inevitably will lead to interference with operational decisions or very detailed and information intensive relative to the alternative are unfounded.
- The chief difference between the approaches is the extent to which regulated entities can use their information asymmetry to bias regulatory decisions — with the use of the building block approach more prone to being susceptible to the regulated entities' comparative

> information advantages.[48] For this reason, there may be benefits from developing a methodology for making greater use of historical productivity estimates to set forward-looking X factors. However, there are a number of implementation issues to resolve in order to apply such methodologies, and the building block approach remains a robust and appropriate methodology for setting the X factor in price caps until such alternatives can be developed and demonstrated to be superior.

It is noted that the Code may preclude — or at least make difficult — the use of productivity estimates to derive the X factor in a price cap. BHPB would be amendable to providing regulators with the ability to use indicators like total factor productivity estimates to overcome the information advantages of the service providers when setting the X factor, provided that prices were required to be reset in line with cost at a price review. However, BHPB considers that the building block approach should remain the approach for setting the X factor until such alternatives can be developed and demonstrated to be superior.

Regarding the length of the regulatory period, BHPB considers that the current provisions that provide the regulator with discretion are appropriate. It is noted that the objective of incentive regulation is to provide the service provider with a commercial reward to reduce costs so that prices can be reduced to customers — so, in effect, everyone benefits. The objective of benefiting all participants would not be achieved by permitting service providers to retain the benefits for an unnecessary length of time.

One of the most important inputs for determining a service provider's actual cost at a price review is to establish the value of its regulated assets at that point in time. BHPB's views on this matter are set out next.

Valuation and Revaluation of the Regulatory Asset Base

The Code provides the regulator with a wide discretion as to how to determine the starting regulatory asset base for a pipeline or distribution system when an existing asset is first regulated under the Code.[49] However, once that initial value is set, the Code requires that it be rolled forward, that is updated at the next price review by adding in capital expenditure and deducting depreciation.[50]

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48 BHPB's own experience is that a sudden jump in the expenditure requirements for regulated entities inevitably is required (or at least argued to be required) not long after the start of the next regulatory period.

49 Section 8.10-8.11. New pipelines are valued at cost (sections 8.12-8.13).

50 Section 8.9. The regulatory asset base would also be updated to reflect historical inflation where a real rate of return on the regulatory asset base was reflected in the previous period's tariffs (section 8.5A). In addition, redundant assets may be removed, but only if the regulator has foreshadowed this, and reflected the chance of redundancy either in the rate of depreciation of rate of return for the previous regulatory period (section 8.27-8.29).

In its numerous submissions to the many price reviews around the country, BHPB has argued against the use of the depreciated optimised replacement cost (DORC) valuation methodology to set the starting value for downstream regulated transmission and distribution assets. In BHPB's view, the tendency for most regulators to adopt the DORC methodology has resulted in a substantial and unnecessary windfall gain to the regulated entities, at the expense of users.

However, in BHPB's views the most important feature of the Code — and its clear advantage over the National Electricity Code — is that, once the initial regulatory asset base is set, that value is set forever, and there is no further reopening of that value (with the exception of identified redundant assets) at future price reviews. Updating the regulatory asset base to reflect new capital invested and the return of funds to investors (regulatory depreciation) provides greater certainty that investments made in the networks will be recovered, and thus provide further incentive for investment. From the perspective of participants in upstream or downstream activities, precluding the regulatory asset base from being re-opened is a critical constraint on the ability of service providers to use their position of information advantage to continue to earn further windfall gains over time at the expense of upstream and downstream development.

The provisions in the Code that require the regulatory asset base to be updated by the rolling-forward method are a main strength of the Code and should be endorsed by the Commission.

Up front approval of reference tariffs

In its Issues Paper,[51] the Commission has sought comment on whether the concept of the reference tariff in the Code provides sufficient prescription to reduce the cost of obtaining access, while also providing sufficient scope for parties to negotiate arrangements that suit their own requirements. BHPB's view is that the current arrangements under the Code with periodic price reviews to establish reference tariffs and negotiation for different services (with resort to arbitration) represents the most effective arrangements.

While no alternative model is discussed, it would appear that the Commission would consider case-by-case arbitration — as included in Part IIIA of the Trade Practices Act 1974 — to be the alternative. As the Commission is aware, under the Code service providers are required to have one or more reference tariffs approved as part of their access arrangement. The reference tariff is a tariff that a service provider has a right to charge — and the user has a right to pay — for a specific

[51] Productivity Commission, *Review of the Gas Access Regime*, Issues Paper, July 2003, p.18.

service, provided there is spare capacity in the pipeline. However, the parties are free to negotiate around this tariff should they desire.

It is BHPB's view that the current level of up front prescription on pricing in the Code — the requirement for one or more reference tariffs to be approved — is not only appropriate, but far superior to the alternative of case-by-case arbitration. In assessing the relative merits of the alternatives it is important that the relevant objective be borne in mind: *the regime should deliver a price for access that reflects cost*. The question for the Commission is how best to deliver this outcome. We would be concerned if instead, the Commission focused on the different question of how to establish a regime that forced parties to negotiate, even though one is a monopolist.

The regulation of the monopoly elements in the energy industry through periodic price reviews — with the use of incentive regulation to promote efficiency as discussed above — is the standard model for regulation in developed countries around the world. In contrast, the case-by-case arbitration model for setting regulated charges is an unknown for energy. Probably the main reason for the ubiquity of the 'price approved up-front' model is the similarity of services that almost all access seekers demand — that is to have gas transported from point A to point B. In the context of many access seekers all wanting the same service it is a far more efficient regulatory process to set prices through one process for all access seekers.

Moreover, there is no sound basis in efficiency terms for discriminating between access seekers, given the model for access in the gas industry. An access price is efficient if it results in efficient prices to final customers and for the vast majority of cases, the access seeker will be the retailer (who then markets the bundled product to final customers). The standard charging arrangements for gas transportation supports efficient pricing for final customers by retailers.

- for transmission, the standard form of charging is to charge a retailer according to the capacity it has reserved,[52] and then to permit trading of that capacity. This form of charging will imply that the opportunity cost to the retailer of serving a particular customer at any point in time will reflect the opportunity cost of the capacity required to serve that customer. Competition amongst retailers should lead to this opportunity cost of capacity being reflected in final charges.
- for distribution, the standard form of charging is to charge a retailer according to the identity of the customers it serves, and for distributors to set efficient charges for that customer's use of the system (ie cost-based tariffs efficiently structured, and possibly some 'pooling' for domestic customers). For a retailer, that distribution charges — whatever its structure — reflects the opportunity cost of serving that customer, and competition amongst retailers should lead to this opportunity cost of capacity being reflected in final charges.[53] In the case

[52] This model applies for all pipelines except for the Victorian transmission pipelines that are operated by VENCorp.

[53] This matter is discussed further in footnote 61, and the associated text.

of very small customers, it may be that the most efficient approach involves some cost 'pooling'.

The efficiency properties of these arrangements rely on the same charging arrangements applying to all retailers. Accordingly, negotiated differences in the charges between retailers — which would appear to be the attraction of case-by-case arbitration — could only lead to a reduction in the efficiency of the prices that are charged to final customers.

Case-by-case arbitrations may also have a number of other detrimental effects on the efficiency of the regulatory arrangements — with adverse effects on the service provider — for example:

- it may be difficult to provide service providers with certainty that they can retain the benefits of efficiency gains for a stated period if access prices can constantly be re-arbitrated;
- the threat of constant re-arbitrations may reduce the certainty that service providers will be able to recover all of their capital over the life of an assets (for example, if the provider adopts a tariff path that defers the recovery of capital in order to encourage use of the asset in its early years); and
- where access prices for different users are set at different points in time, the service provider will have an incentive to change its method of allocating costs between arbitrations in order to allocate more than 100 per cent of the total cost — the inevitable implication of which is that the regulator would be forced to provide the service provider with less flexibility over cost allocation if prices are set in different arbitrations at different times.

In addition, the sole reliance on case-by-case arbitration has a number of aspects that would be likely to impede the development of sustainable competition in the markets upstream and downstream of the monopoly transportation infrastructure.

- first, as the experience in telecommunications bears out, arbitrations provide substantial scope for a powerful incumbent to delay access.
- second, the cost associated with pursuing arbitration implies that an arbitration mechanism inevitably will favour large access seekers (retailers) over small access seekers. This may rule out the entry of niche market competitors in the industry and the opportunity for a large industrial customer to negotiate gas supply directly with a producer
- third, as well as reducing the efficiency of prices to final customers (as discussed above), case-by-case arbitrations would also provide greater scope for a vertically integrated incumbent retailer and distributor to re-shuffle its costs around to a new barrier to each access seeker.

Of course there will be other services that may be sought (such as the right to interconnect a new pipeline to the existing system) and some access seekers may seek alternative commercial terms (such as a longer contract or alternative arrangements for meeting credit support requirements). However, the Code permits negotiation for other services or for variations on the standard service, with arbitration as a fallback, and so provides ample flexibility for any such mutually acceptable outcomes.

Indeed, it is possible under the Code for regulators to encourage service providers and access seekers to negotiate elements of an access arrangement for which a

commercial resolution is considered possible and desirable, and to take account of any such agreement when assessing the access arrangement. A case in point is the approach that was adopted by the Victorian Essential Services Commission in its recent review of the Access Arrangements for the Victorian gas distributors. The Essential Services Commission (then the Office of the Regulator-General) proposed drawing upon negotiations between the retailers and distributors when assessing the terms and conditions in the distributors' access arrangements. Its stated intention was expressed as follows:[54]

> The purpose of this letter is to clarify the process the Office proposes to advance the work on drafting the distributors' Access Arrangements where possible prior to the receipt of their formal submissions on 29 March 2002. Related to this, it also clarifies the process proposed to rationalise the existing regulatory instruments to achieve greater clarity and simplicity in the regulatory arrangements.
>
> The Office's intention is to facilitate the drafting and public consultation on as many of the components of the distributors' Access Arrangements as possible prior to the receipt of the distributors' formal submissions on 29 March 2001. It is expected that a degree of consensus may be possible between the relevant interested parties on a number of the components of the new Access Arrangements, in turn, vastly simplifying the formal assessment process.

and further expressed its view that:[55]

> While it is envisaged that it would be difficult for such a working group to achieve a consensus on all of these terms and conditions, the Office would expect that a consensus position could be reached on the vast majority, thus leaving comparatively few matters upon which the distributors would need to make separate proposals in their formal submissions. While the Office notes that it cannot be bound by a consensus agreement of that working group, the Office does consider that its application of the relevant provisions in the Gas Code would permit it to give significant weight to any such consensus.

The end result was that the vast majority of the terms and conditions were settled through commercial negotiation and the Essential Services Commission's task in assessing these provisions was reasonably straightforward.[56]

It is interesting to note that the same views were expressed by in the report from one of the original working groups that was established under the Gas Reform Task Force in 1995. The report of this working group was important for two reasons — the first was that the report was a consensus report from a group comprised mainly

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[54] Office of the Regulator-General, *Composition of the Access Arrangements and the Implications for Other Regulatory Instruments*, Open Letter to the Gas Distributors, 14 September 2003, p.1.

[55] Office of the Regulator-General, *Composition of the Access Arrangements and the Implications for Other Regulatory Instruments*, Open Letter to the Gas Distributors, 14 September 2003, p.3.

[56] Essential Services Commission, *Final Decision: Review of Gas Access Arrangements*, October 2003, pp.20-22.

of industry representatives (which included BHPB and a major Australian pipeline company, East Australia Pipeline Company[57], second, the proposals in this report ultimately set the framework for the Code. Its consideration of this matter is reproduced below. BHPB considers that its findings on this matter remain relevant today.[58]

> Access regimes based on negotiated outcomes are intended to deliver the following benefits:
>
> - Flexible pricing that can generate more efficient use of the pipeline (e.g. offering discounts to users that are more price sensitive and charging higher tolls to users that are less price sensitive to attempt to increase pipeline utilisation);
> - Less regulatory intervention, leading to a perception of lower "regulatory risk in the industry, with avoidance of the need for prices to be set by a regulator:
> - this point reflects the concern with the difficulties surrounding prices being "set" by a regulator. This point is discussed further below.
>
> The critical assumption behind the "negotiation" model is that pipelines will perceive the threat of arbitration as a "credible threat" that encourages pipeline companies to negotiate in good faith and not seek to exploit their market power to earn excessive returns.
>
> The Working Group considers, however, that the threat of arbitration may not lead pipeline companies to negotiate "competitive" prices. The expected result is:
>
> - Small potential shippers — for whom the time and cost of arbitration would make this avenue prohibitive — either will enter contracts that provide the pipeline company with an unfair advantage, or decide not to enter a market.
> - Large potential shippers are likely to make use of the arbitration mechanism to force a test of the pipeline company's claims, driven mainly by the large information asymmetry that will always exist between the parties.
>
> The implications of this are as follows:
>
> - The end result would be prices set by an arbitrator (thus not delivering the key benefit of negotiation), albeit after a string of disputes rather than being set or approved by a regulator initially;
> - The creation of principles by case precedent (i.e. through prices being set by the arbitrator) would create a large degree of uncertainty, outweighing any perceived uncertainty from the up front regulatory intervention;
> - Even if parties are able to appoint a mutually acceptable arbitrator, a string of precedents may not arise, which may lead to:
> - the uncertainty from the negotiated access regime continuing into the future;

---

57 At that time, the East Australia Pipeline Company was 51 per cent owned by AGL, and the remaining 49 percent by Nova and Petronis before the establishment of APT.

58 Gas Reform Task Force, *Transmission Working Group Report to the Gas Reform Task Force*, October 1995 in: Gas Reform Task Force, Scoping Study Report, Information Appendices, 22 December 1995.

  - inconsistencies arising between determinations; and
  - risk a lack of public accountability of the determinations;
- Adversarial style arbitrations encourage the parties to become antagonistic, which my impede the cooperation between pipeline companies and shippers that is required for the long term growth of the gas industry;
- Arbitration typically involves large costs and significant delays, thus only large participants are likely to make use of this form of relief, which, together with the time delay, may provide significant protection to an incumbent; and
- As noted above, market access would be skewed in favour of the large market participants (potentially excluding high value adding niche market services).

Moreover, the Working Group considers that the perceived benefits from pipelines and shippers being able to negotiate individual contracts may be overstated:

- In the future, pipeline companies are likely to offer standard services (albeit far more services than currently available) to reduce the transaction costs of dealing with many shippers and to facilitate capacity trading; and
- Pipeline companies are likely to offer the standard services on a same price for same service basis (for the reasons discussed above).

It is noted that the ability for an arbitrator to re-open tariff policies on a case-by-case basis may make some forms of tariff policies (that could be desirable in a developing market) unattractive to pipeline companies.

- For example, one desirable tariff policy is for haulage charges to be set to earn a target rate of return in NPV terms over some period, based on forecast demand growth, and with tariffs back-ended in order to stimulate initial demand.

  Under this type of tariff policy, the pipeline could assume a significant degree of risk. Moreover, the annual rate of return towards the end of the period may need to be quite large to ensure that the initial rate of return target is met.

  The threat of a regulator re-opening the tariff policy mid-way through the time could alter significantly the risk profile of the policy, or even make it non viable.

<u>Conclusion:</u>

1. Access regulation for transmission pipelines should have a strong focus on supervising the tariff policies of pipelines (to control monopoly behaviour) in addition to preventing pipeline companies from barring other participants from entering upstream and downstream industries to protect the pipeline company's related interests.
2. Negotiated haulage contracts without regulatory involvement are expected to contain significant monopoly rents or be excessively time consuming to effect. The inefficiencies caused by excessive rents are likely to outweigh potential costs from price regulation.
3. In practice, a large number of access negotiations are likely to go to arbitration. These arbitrations will be initiated primarily by the large users. Access arbitration will result in haulage charges being set by an arbitrator. The end result is likely to be tariff policies determined by an arbitrator, but only after a string of arbitrations,

which are costly and very time consuming, and significant uncertainty for all participants would have been created in the meantime.

- The Working Group notes that a private arbitration of an access dispute would require the arbitrator to apply public interest criteria. Therefore, arbitration is a *de facto* regulatory process.

4. The "benefits" from negotiated individual contracts may be overstated as standard form contracts to promote administrative efficiency may be preferred in a competitive gas market.
5. Case-by-case arbitration may increase the risks associated with the types of tariff structures that may be desirable in the current stage of development of the Australian gas market. This would result in the tariff that is associated with such a tariff structure being higher, and may lead to such tariffs not being offered at all.

5.2 Ring Fencing and Vertical Integration

Model for Reform and Problems with Vertical Integration

The reforms to the natural gas industry were discussed in chapter 2. In essence, the model followed was to unbundle the separate activities of the natural gas supply chain into their economically distinct elements, regulate only the remaining monopoly components, but also to regulate in a manner designed to promote competition into those elements where sustainable competition would be possible. For the natural gas industry, the monopoly components are the downstream transportation elements, and the elements where sustainable competition is possible are the production and retail elements. This model for reform was similar to that followed in many countries around the world.

At the time that these reforms were introduced, it was known that the existence of linkages between the monopoly and potentially contestable elements would create problems for the introduction of sustainable competition into the related markets. Indeed, the Industry Commission recognised this fact in its report that commenced the reform process:[59]

> Most public utilities reject structural change. However, without it, many of the current inefficiencies may become even more deeply entrenched, significant change might never emerge and the nation could suffer the ongoing handicap of electricity and gas industries which are not performing to their full potential.

The basis of the concern about the existence of linkages between the regulated and potentially contestable activities is that integrated businesses have a direct incentive

59 Industry Commission, *Energy Generation and Distribution*, Report No 11, Vol 1: Summary and Recommendations, May 1991, Preface.

to act in a manner designed to thwart the objectives of the reforms. In particular, where the monopoly element is regulated, the business has a direct incentive to attempt to use its market power to regain the lost rents elsewhere — and vertical integration is an obvious tool to achieve this end. Taking the relevant example for the Australian gas industry — a vertically integrated retailer and distributor — the obvious incentives for the entity include the following:[60]

- *transfer the rents to the retail business* — both the distributor and retailer have an incentive to do anything that they can to preclude or delay the introduction of competition into the retail market, and then to do whatever they can to minimise the extent of rivalry amongst retailers — and so recover the potential profits that have been removed from the regulated activity. The tactics for achieving this goal are endless — several examples are set out in Box 5.1 below.
- *transfer the rents to a related activity* — the integrated entity will have an incentive to attempt to allocate the costs associated with undertaking related activities to the regulated business. This can be done directly — just by undertaking an unreasonable cost allocation. It can also be achieved by setting up a separate entity to construct or manage networks, and to charge itself an inflated price for those services.

Box 5.1: Tactics to transfer rents to an affiliated retailer

Some of the strategies for a distributor to use its control of the monopoly distribution infrastructure to capture rents in its retail business include the following:

- Absent an effective access regime with regulated access prices set up front, the distributor would have an incentive to force new entrants to go through a costly arbitration process even to find out if entry into the market is possible.
- Once prices are set, the distributor would have an incentive to delay entry by raising a number of technical issues to be resolved — such as how gas should be allocated between retailers on an open access system (given that the deliveries from individual retailers cannot be separated), how issues like gas balancing should he handled, as well as numerous other technical issues number of what appear to be legitimate issues to attempt to stifle the transfer of customers (and hence, competition). For example, it will argue that it needs to delay the switching of customers that have not paid debts — and require a period to check this out — and argue about such matters as who should be responsible for deliveries to supply points where the old customer has moved and a new one has taken possession of the premises (and commenced using gas). As part of the technical concerns that would be raised, the distributor would also have an incentive to seek to force new entrants to bear costs not borne by its affiliate.
- And, even once all of the rules for the new market have been set, the integrated entity would have a continuing incentive to use information gained from its role as distributor to provide its retailer with an advantage over new entrants.
- Lastly, the distributor would have a strong incentive to provide discounts to its affiliated retailer and to seek to recover the revenue lost through discounting from other customers. And, even if discounts provided to an affiliated retailer cannot be recovered, the integrated business may have an incentive just to drop its retail prices to levels that would make competition for a group of customers

60 In the Transmission Working Group Report to the Gas Reform Taskforce in October 1995, vertical integration was one of the two identified (and inter-related) concerns that justified the need for regulation of gas transmission pipelines. See Allen Consulting Group paper *Review of the Gas Code: Commentary on economic issues*, chapter 2.

unsustainable in order to force out a potential competitor before it became established, and to seek to recover the shortfall — and more — once the competitor has been forced out.

The adverse implications of these actions are obvious, and include the following:

- Customers and producers would continue to pay higher transportation prices than required, stifling investment in related markets, thus denying the wider dynamic efficiency benefits expected from the reforms;
- The incumbent retailer may displace a much more efficient new entrant, and continue to saddle the industry with inefficiency; and
- The additional dynamic benefits expected from competition in the retail function — in the form of more innovative tariff structures and service offerings, and hence price signals that encourage a better use of existing capital — would be foregone, and the continuation or reimposition of regulation of retail (delivered) prices a likelihood.

We would also dispute whether there are economies of scope between retail and distribution activities that would provide efficiency gains from integration. The emergence of separate retailers in some markets (discussed below) is testament to this. Moreover, the one concrete advantage often claimed for vertical integration — that integration can permit more efficient pricing strategies — would not appear relevant for gas distribution.[61]

In the presence of vertically integrated firms, the only response to the incentive for integrated firms to act as described above is to address the symptoms — that is, to limit the extent to which firms can stifle competition or otherwise transfer rents to a related business, as discussed above. The principle means of addressing such actions is to have an effective access regime in place with sufficient powers to the regulator, robust regulatory accounting requirements, ring fencing requirements and ancillary powers for the regulator to address these actions, and a vigilant regulator. BHPB's comments on the form of access regime were set out above, and its views on the adequacy of the Code for supporting robust regulatory accounting requirements and on the identity and resourcing of the regulator are set out in chapter 6. The remainder of this chapter deals with the need for — and adequacy of — the ring fencing requirements set out in the Code.

Before addressing the extent of vertical integration in the Australian gas industry, a cautionary note about what can be achieved with ring fencing (and other) measures is appropriate. The role of ring fencing arrangements (and access regimes) is to *limit the ability* for integrated firms to undertake the actions set out above; however, such measures cannot limit the incentive for the firms to want to undertake such actions. Regulated entities can undertake world-class corporate engineering and structure themselves to make it look like a retail business acts independently. However, if both entities have the same set of shareholders, then all will pursue the interests of the integrated firm — and it will be obvious to all of the 'separate' entities exactly what is in the interests of shareholders.

Vertical Integration in the Australian Gas Market

In chapters 2 and 3, it was noted that, over the last ten years, there has been a substantial change to both the structure and to the identity of the players in the

[61] For example, it is standard practice for energy distributors to set transportation charges to reflect the customers served. Therefore if a retailer serves a particular customer, it pays the tariff in respect of that customer. With competition in the retail market, the tariff structure of the distribution tariff should be reflected in the final tariff. This is sometimes described as the tariff for the monopoly element 'orienting' the final charge (see Laffont, J, J. Tirole, *Competition in Telecommunications*, (MIT press, Cambridge), 2000, pp.80-84). Thus, the distributor does not have to be vertically integrate into retailing to ensure that efficient tariffs are set for final customers.

Australian gas industry. Part of this change has occurred as a result of privatisations, but much has also occurred as a result of the restructuring and sale or separate listing of existing businesses. However, notwithstanding these changes, substantial vertical integration exists in many of Australia's gas markets. In our view this makes strong ring fencing provisions (and the rigorous enforcement of those provisions) between the parts of a business regulated by the Code and those that are not crucial. The current extent of cross-ownership in the major markets is summarised in Box 5.2.

Box 5.2: Vertical Integration of Gas Utilities

New South Wales

AGL Networks Limited (a 100 per cent owned subsidiary of AGL) owns the pipelines and distribution networks that cover the greater Sydney area, including Newcastle and Wollongong.

AGL Retail Energy (a 100 per cent owned subsidiary of AGL) is the dominant retailer in NSW, with approximately 880,000 customers or 90 per cent of the NSW retail market. Since the introduction of full retail contestability, a number of new energy retailers have obtained licences to retail gas in NSW. However, these companies have yet to obtain a significant market share in New South Wales.

AGL has a 30 per cent interest in the Australian Pipeline Trust (APT), which owns the Moomba to Sydney Pipeline (which brings gas from Moomba to the greater Sydney area, in competition with gas from the Gippsland basin). APT also has the first right of refusal on any new transmission pipelines developed by AGL.

AGL has also established the separate — but wholly owned — entity Agility, which manages infrastructure assets and provide services to owners of infrastructure assets. Agility currently has contracts to manage the pipeline assets of APT, AGL Gas Networks as well as managing non-AGL assets including those owned by Country Energy.

Victoria

There are three geographically-separate gas distribution systems in Victoria. However, while these distributors were sold 'stapled' to a retailer, the original retail and distribution boundaries were non-coincident —approximately half of a distributor's customers were served by its retailer.

TXU Networks (wholly owned by TXU) owns one of the gas distribution business, and TXU Retail (also wholly owned) is one of the three incumbent gas retailers in Victoria — but note the comment about initial service areas above. It has 421,000 customers, or approximately 27 per cent of total customers. TXU also owns TXU Trading, which wholesales, trades and stores gas for large customers. TXU also has a 33 per cent interest in the SEA Gas Pipeline, which will transport gas from Port Campbell in Victoria to Adelaide.

Envestra owns the second of the gas distribution businesses, and does not have any direct interest in upstream or downstream activities. However, Origin Energy has a 19.1 per cent interest in Envestra and Origin Energy Asset Management, a 100 per cent owned subsidiary of Origin Energy, manages and services Envestra's distribution pipelines on behalf of Envestra. Origin Energy retails gas to approximately 564,000 customers in Victoria, or approximately 36 per cent of the Victorian market. Origin Energy also has a number of interests in gas production, which are or may become potential alternative supply sources for Victoria, which include Origin Energy Petroleum Pty Ltd, a fully owned subsidiary of Origin Energy and has interests in production and exploration in a number of contracts in the Otway Basin, and a 37.5 per cent interest in the BassGas Project, which is an exploration and production project in the Yolla gas field. Origin Energy has a contract to purchase 260 PJ of gas from the Yolla gas field over 20 years.

Multinet, which is the third of the gas distributors, is owned 19.9 per cent by AlintaGas and AMP Henderson. AlintaGas has entered into a long-term management agreement to operate, maintain and manage all the network assets of United Energy, Multinet and AlintaGas Networks. There is currently potential for AlintaGas to retail gas in Victoria.

South Australia

Gas is distributed through gas networks owned by Envestra. As noted above, while Envestra does not have interests in potentially contestable activities, Origin Energy has a 19.1 per cent interest in Envestra's infrastructure assets. These assets are managed by Origin Energy Asset Management, a 100 per cent owned subsidiary of Origin Energy.

Origin Energy is currently the only gas retailer to households and small businesses in South Australia and have approximately 330,000 customers.[62] Origin Energy also has an interest in the Cooper/Eromanga Basin gas field, and interests in the Katnook gas field in the Otway Basin. Origin Energy also has a 33 per cent interest in the SEA Gas Pipeline, which is a transmission pipeline that will transport gas from Port Campbell to Adelaide.

Western Australia

Gas is distributed through networks owned by AlintaGas Networks, which is 75 per cent owned by Alinta. AlintaGas Retail is the dominant retailer and currently the only retailer of natural gas to residential households in Western Australia.

Queensland

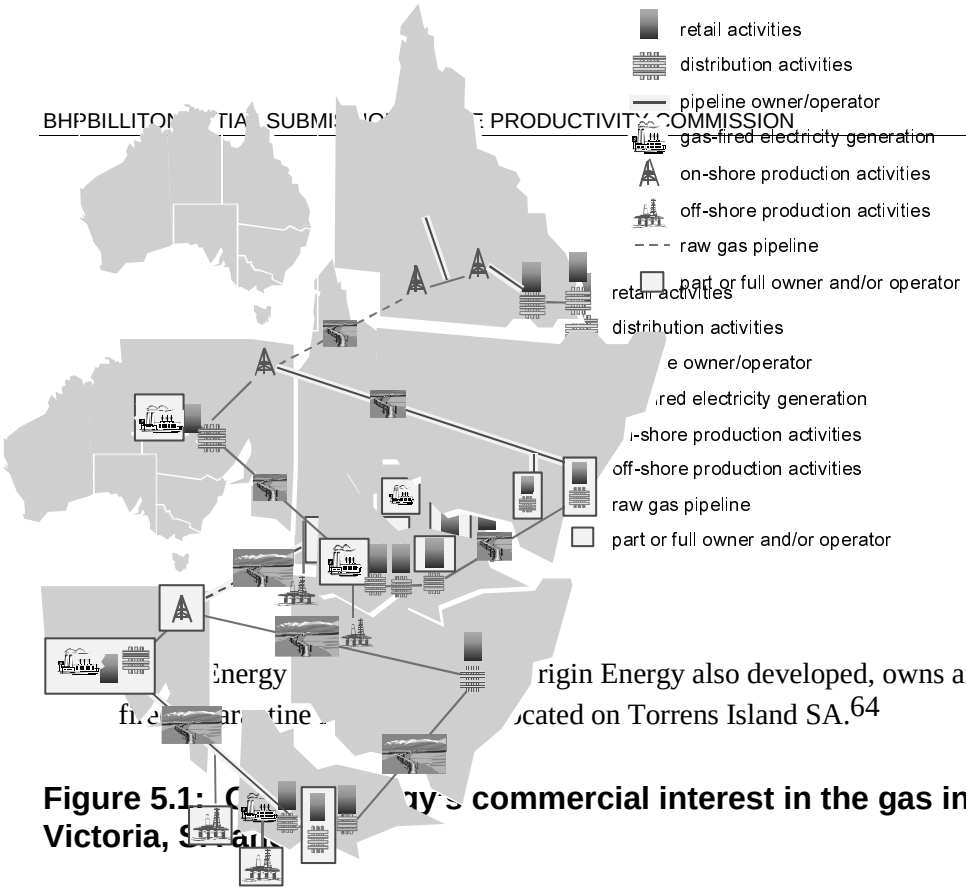
Envestra owns the distribution networks in northern Brisbane, Rockhamption, Gladsotne, Maryborough and Hervey Bay. These assets are managed by Origin Energy Asset Management, a 100 per cent owned subsidiary of Origin Energy. Origin Energy is the dominant retailer through this network, and has the exclusive franchise to serve small customers in the area covered by this network. Origin Energy also has interests in a number of these production operations. For example, the Oil Company of Australia (an oil and gas exploration in Queensland which is 85 per cent owned by Origin Energy) has interests in producing and supplying coal seam methane gas into the Wallumbilla to Gladstone Pipeline from the Bowen Basin. Origin Energy is also part owner of the Cooper/Eromanga Basin joint venture, which serves the Queensland market.

ENERGEX owns the gas distribution networks in the south of Brisbane, and down to the Gold Coast. ENERGEX is the dominant retailer through this network, and has the exclusive franchise to serve small customers in the area covered by this network.

It is important to consider the activities of businesses across State borders. Figures 5.1 and 5.2 depict the current commercial interests of Origin Energy and AGL (as described in Box 5.1) in the gas industry, in Queensland, NSW, the ACT, Victoria and SA. The extensive network of commercial interests and linkages throughout the gas industry is clear. The relevance of such linkages is the commercial incentives they create for the business entity as a whole. Both AGL and Origin Energy also have interests in gas-fired electricity generation:

- AGL owns and operates gas-fired power stations in Somerton Victoria and in Hallet South Australia;
- Origin Energy developed, owns and operates the Ladbroke Grove Power Station in SA and also operates the adjacent gas plant on behalf of the company and its joint venture partner Australian Worldwide Exploration. Electricity produced by the power plant is traded by

[62] JPMorgan *Infrastructure and Utilies Directions*, 14 April 2003.



Energy rigin Energy also developed, owns and operates the gas-fi ar tine cated on Torrens Island SA.[64]

Figure 5.1: C y's commercial interest in the gas industry in NSW, Victoria, S a

Figure 5.2: AGL's commercial interests in the gas industry in NSW, Victoria, SA, Qld and the ACT

63 Media Release: Origin Energy "delivers the goods" with innovative Ladbroke Grove power project, 16 August 2000, available at www.originenergy.com.au/news.

64 Media Release: Quarantine Power Station Opened by Premier Rann, 23 Apr 2002, available at www.originenergy.com.au/news.

Thus, various degrees of vertical integration exist between distribution and other activities in all of the major natural gas markets. Moreover, even where the distributor appears to be independent — such as Envestra — the fact that its networks are operated by an entity that is also a retailer and producer could be expected to provide it with perverse incentives over the operation of the system, as well as access to information about competitors' future plans that could be used to provide its retail arm with an unfair advantage. For example, Origin Energy identifies that one of the two key elements of its network business is its Origin Energy Asset Management (OEAM). OEAM receives a management fee of three percent of revenue for the distribution assets it manages in South Australia and Queensland.[65]

Out of all of the markets the extent of vertical integration in the NSW gas market is the greatest . AGL is a major distributor and dominant gas retailer, in NSW. In addition, AGL has a significant interest (and a contract to operate) the pipeline from the Cooper/Eromanga Basin, whereas most of AGL's potential competitors in NSW may soure gas from the Gippsland Basin (through the Eastern Gas Pipeline). Its interest in protecting the value of its upstream (transmission) interest may provide stronger incentives to deter competition from becoming established in NSW.[66]

BHPB previously has provided the Commission with a report by NERA describing in detail the incentives of incumbents with respect to deterring new entry, and on what actually has occurred in a market.[67] It included evidence of a stunning failure of the regulatory regime, which was that Duke was forced to spend $28 million to construct a section of pipeline that runs parallel to an existing pipeline purely because it could not get access to the existing system on reasonable terms. BHPB again commends the NERA report to the Commission's consideration. That report also contained a number of recommendations to improve the competitive situation in markets where significant vertical integration exists.

At the same time that vertical integration in the gas industry is increasing, so is the concentration in the retail sector. Figure 5.3 demonstrates the consolidation of energy retailers in Eastern Australia. Such consolidation combined with the fact that five of the eight retailers are government owned does not support the notion of a highly competitive retail sector in the gas industry which was one of the objectives of the initial reform process (discussed in chapter 2).

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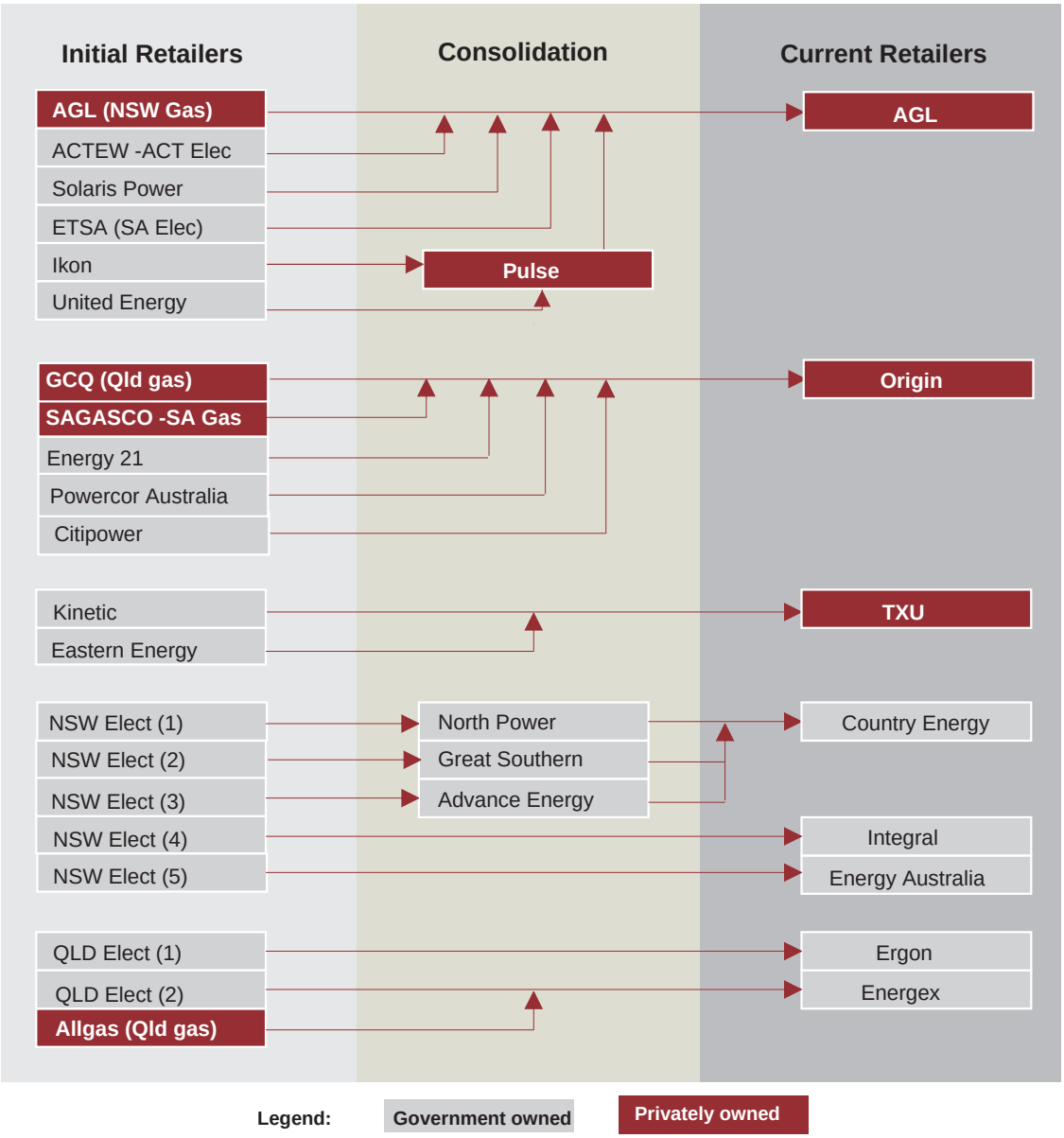
65 Origin Energy, *Annual Report, 2002*, p 22, available at www.originenergy.com.au

66 AGL's additional incentive to stifle competition may arise because when AGL Retail loses a gas customer, its retail business would lose revenue and the transmission business it partly owns would also lose revenue.

67 Paper submitted to the Commissions Review of Part IIIA Inquiry: Makholm, J.D. and Quinn M.J. 2000, *Seeking Genuine Gas Competition in NSW* National Economic Research Associates, February 2000.

Figure 5.3: Consolidation of Eastern Australian Energy Retailers



Source: Karen Moses Executive General Manager, Wholesale & Trading, Origin Energy, Presentation UBSW April 2002 *Growth Prospects in Competitive Energy Markets* and BHPB analysis.

Implications for the Gas Code

The analysis above has demonstrated that vertical integration is a problem in the Australian gas industry, and hence the potential for vertically integrated entities to stifle new entry into potentially competitive markets and thus the emergence of sustainable competition in those markets. Accordingly, robust arrangements ring-fencing requirements and related measures remain essential — the

consequences of not responding to the threats associated with vertical integration are substantial.[68]

BHPB is generally supportive of the ring fencing requirements and related measures currently contained in the Code and Law,[69] the essential features of which are as follows:

- to ensure that confidential information that is either provided to a service provider, or which the service provider obtains in the course of its business, about an access seeker is not disclosed to any other person without the approval of the access seeker;[70]
- to ensure that the marketing staff of the monopoly business do not also work for a related business (such as a retailer), and that the marketing staff of a related business do not also work for the monopoly business;[71]
- to permit the regulator to impose additional ring fencing requirements;[72]
- a requirement for the regulator to approve contracts between the service provider and an affiliate;[73] and
- a general power for the regulator to take action against conduct for the purpose of preventing or hindering access to a pipeline network.[74];
- penalty provisions for breaches of specified ring-fencing provisions.

BHPB notes, however, that one of the potential actions that an incumbent vertically-integrated business may undertake is just to drop its retail prices — thus making competitors unviable — with the purpose of making higher profits after new entrants have been deterred. Currently, there are no powers under the Code to address anti-competitive pricing practices of the affiliate retailer — the only party in a position to address such behaviour is the Australian Competition and Consumer Commission under section 46 of the Trade Practices Act 1974.

With the exception of a regulator's information gathering powers, BHPB's main concern with the operation of the Code's ring-fencing provisions is not the provisions themselves, but rather the extent to which they are — or rather, are not — enforced by regulators. NERA has commented that the problems with introducing sustainable competition in the face of a vertically integrated operator

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68 See previous discussion in this section under the heading 'Model for Reform and Problems with Vertical Integration'. As noted above, robust regulatory accounting requirements and a robust access regime are also essential.

69 This statement excludes the powers given to regulators to gather the information necessary to prevent anti-competitive cross-subsidisation of its retail business and cost-shifting to its regulated business generally. This issue is addressed in chapter six.

70 Code, sections 4.1(f), (g).

71 Code, sections 4.1(h), (i).

72 Code, sections 4.3-4.11.

73 Code, sections 7.1-7.6.

74 Law, section 13.

have been faced and overcome in a number of other countries — what is required for Australia is robust application of the Code by the regulator.[75]

Breaches of ring-fencing provisions can result in the application of civil penalties (ranging from $50 000 to $100 000) or court action can be taken to seek to recover loss or damage caused by the breach of the requirements.[76] While the existence of these provisions is critical, there are practical difficulties in their application, which somewhat negates their effectiveness as a deterrent. Given the resources required to take court action, only the very largest players would be in a position to allocate the resources to pursue a damages claim against a well entrenched (and thus highly motivated) incumbent. If court action were undertaken obtaining evidence that ring-fencing provisions have been breached would be difficult. Further, to establish loss or damage for the purpose to taking court action, could require establishing the consequences of something that did not happen. For example, if the consequence of breaching ring-fencing provisions was to deter the entry of a new retailer, losses and damage arise due to a less competitive market. However, this may mean that prices and service offerings remain unchanged. These factors reinforce the need for regulators to vigorously monitor compliance with ring-fencing provisions and if breaches occur take necessary action that results in strong penalties being imposed as both a penalty and future deterrent.

BHPB's proposals for increasing the preparedness and capacity of regulators to perform the actions entrusted to them are set out in section 6.6.

[75] Makholm, J.D. and Quinn M.J. 2000, *Seeking Genuine Gas Competition in NSW* National Economic Research Associates, February 2000, pp.2-3.

[76] Law, Schedule 1, section 36(1)

Chapter Six

Improving the operation of the Code

This chapter discusses the effective operation of regulatory instruments: the Code and to a lesser extent the Gas Access Pipelines Law ('the Law'). The chapter makes recommendations to support more effective implementation and administration of the Code and hence more effective regulatory processes and outcomes.

6.1 Introduction

The first decision under a regime substantially similar to the Code was by IPART in 1996, followed by the Victorian Office of the Regulator-General and the Australian Competition and Consumer Commission in 1998. Since then, each of the jurisdictional regulators have made regulatory decisions under the Code, and several second round decisions have been made. In BHPB's view, this experience has demonstrated that the Code itself has worked well and overall has achieved its intended objectives (see part two). However, this experience has also identified a number of specific issues the impact on the effective operation of the Code, which fall into two categories — issues associated with the provisions in the Code (or Law), and issues associated with the structures in place to administer and maintain the Code.

The issues that BHPB considers have arisen from the provisions of the Code (or law) include:

- the clarity of the objectives for the regulatory regime (section 6.2);
- the asymmetry of appeal rights and, related to this, the transparency of the process for finalising an access arrangement (section 6.3); and
- ambiguity in regulator's information collection powers (section 6.4).

The issues that have arisen from the implementation and maintenance of the Code are:

- the need for a national regulator for gas transmission and distribution pipelines (section 6.6); and
- the need for an effective Code change process (section 6.7).

The chapter makes recommendations to support more effective implementation and administration of the Code and hence more effective regulatory processes and outcomes.

6.2 Objectives of Code

In its Part IIIA review the Commission highlighted the importance of objectives in any regulatory framework:[77]

> "Clear specification of objectives is fundamental to all regulation. It is particularly important where there is scope for divergence between the intent of regulation and the interpretation of its operational criteria. More specifically, for access regimes to function efficiently, clear objectives are needed to promote:
>
> - decisions that are well targeted to the identified problem and which minimise unintended side effects;
> - greater certainty for current and prospective facility owners, access seekers and other interested parties;
> - consistency among policymakers, the judiciary and those responsible for implementation and enforcement; and
> - regulatory accountability."

The Terms of Reference for this Inquiry refer specifically to the operation of the objectives and principles of the Code as an issue to be examined. The Commission's Issues Paper refers to the multiple objectives in the Code and to the requirement for regulators to balance these in the course of making regulatory decisions. The Commission asks a series of questions about the implications of the current objectives and principles. In brief, our view is that the current objectives and principles in the Code are ambiguous in the guidance they provide to regulators. Clarification of the Code's objectives would result in a more effective access regime for Australia's gas industry.

Direction contained in the Code

The multiplicity of objectives and principles in the Code, and their inter-play, means that regulators have to reconcile competing objectives without clear guidance on the relative weightings to be afforded to each individual objective.

An example of this exists in the requirements of the Code in respect of reference tariffs.

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[77] Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra, p. 124.

Section 2.24 of the Code provides that a regulator may only approve a proposed access arrangement if the regulator is satisfied that the proposed access arrangement contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code (see Box 6.1). Further, section 2.24 requires that the regulator take into account the list of factors contained in section 2.24:

(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 operation 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.

Box 6.1 Elements addressed in sections 3.1 – 3.20 of the Code

Elements addressed in sections 3.1 – 3.20 of the Code:

- Services to be offered (sections 3.1 – 3.2);
- Reference Tariffs and Reference Tariff Policy (sections 3.3 – 3.5);
- Terms and Conditions (section 3.6);
- Capacity Management Policy (section2 3.7 and 3.8);
- Trading Policy (sections 3.9 – 3.11);
- Queuing Policy (sections 3.12 – 3.15);
- Extensions/Expansions Policy (section 3.16); and
- Review and Expiry of the Access Arrangement (section 3.17 – 3.20).

In regard to the reference tariffs and a reference tariff policy, sections 3.3 to 3.5 of the Code require that a reference tariff and reference tariff policy comply with principles set out in section 8. In turn, section 8.1 of the Code requires that a reference tariff and reference tariff policy be designed with a view to achieving the following objectives:

(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

A regulator must assess whether a reference tariff meets the objectives in section 8.1 and, in deciding how to weight and reconcile the 'advice' provided by the section 8.1 objectives, the regulator must have regard to the factors in section 2.24. Rather than providing more specific guidance that may be useful in reconciling competing advice from the subsidiary factors, the section 2.24 factors are cast more widely again — really only informing the regulator that there are competing interests to be considered and also reminding the regulator of a broad range of other factors including the public interest and any other matter that is considered relevant.

The operation of the objectives and principles in the Code was addressed in a judgment by the Supreme Court of Western Australia in a judicial review of the draft decision of the Western Australian Independent Gas Pipelines Regulator on the proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 ('the Epic decision')).

There has been much written about the Epic decision and its implications for future regulatory decisions.[78] A key point of agreement in these commentaries is that the decision has broadened the discretion of regulators under the Code to take into account and give greater weight to factors other than economic efficiency in establishing regulated tariffs. Thus, the judgement has not resolved the issues of multiple objectives and their inter-play and may have actually made regulatory decision making a more complex, uncertain task.

There is a clear need to remove the current ambiguity in operation of the Code's objectives and principles. The Epic decision has not removed this need.

Some commentators have proposed that the Epic decision points to a need for major reform of the Code:

> Ultimately, the main conclusion to emerge from these proceedings is that the Code is desperately in need of reform. It sets goals that are confused at best, inconsistent at worst. It grants regulators vast discretion, while nonetheless imposing mind-numbing, highly detailed, requirements on the precise form (but not substantive outcome) of the regulatory process. And it frees that discretion from effective review by the Courts, which are limited to matters of law, and hence cannot set out clear guidance of the kind

[78] Insert References: Henry's paper and BDW paper (ACG if it's public) any others?

> the Australian Trade Practices Tribunal (now the Australian Competition Tribunal) has so effectively given in respect of the Trade Practices Act.[79]

We do not agree with the view that the Code is 'in desperate need of reform'. As stated in the introduction to our submission BHPB considers that, while a number of specific changes to the Code would enhance its effectiveness, the current regulatory regime for the gas industry is working effectively to contain the misuse of monopoly power and thus promote competition and growth in upstream and downstream markets, while supporting investment in new pipeline projects, where those projects are justified. We would also note that the matter that was appealed in the Epic decision — the setting of the initial capital base — is one of the only pricing matters for which the regulator has to exercise substantial discretion. For many of the pricing elements, the Code provides a clear instruction to regulators.[80]

However, clarifying the objectives of the Code and the inter-play between the objectives and pricing principles is one of the changes that would enhance the effectiveness of the Code.

Finally, we note that, in contrast to the suggestion in the quote above, the Australian Competition Tribunal (ACT) is the appeals body for decisions made by the Australian Competition and Consumer Commission under the Code. In its decisions, the ACT has provided guidance to regulators interpreting the objectives in the Code:[81]

> 48. Thus, for example, the objective listed in s8.1(b) of the Code is 'replicating the outcome of a competitive market'. The outcomes of a competitive market involve not only prices that reflect efficient costs, but a range of non-price attributes (such as conditions of delivery and innovation) tailored to what customers want.
>
> 49. The s.8.1 objectives are those which characterise the outcomes of a market that works optimally. Market performance is a function of price and non-price conduct. Non-price conduct can affect the achievement of the objectives of s8.1.

Unfortunately, this ACT decision was not out at the time that the Epic case was heard, and so the court in the Epic case did not have the benefit of the ACT's views on the matter.

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[79] Ergas H., *Epic in Retrospect and Prospect*, NECG, p. 15 (no date).

[80] For example, even when setting the rate of return, the Code directs regulators to estimate the opportunity cost of capital associated with the regulated asset. While this is a matter upon which judgement may need to be exercised (given the statistical uncertainty associated with estimates of the cost of capital), no further direction from objectives or the like is required.

[81] Australian Competition Tribunal, DEI Queensland Pipeline Pty Ltd v Australian Competition and Consumer Commission [2002] ACompT2 (10 May 2002), available at www.austlii.edu.au.

This guidance complicates the interpretation of the Code by suggesting that the objectives set out in section 8.1 of the Code for a reference tariff and reference tariff policy may apply to other elements of an access arrangement.

An overall objective of economic efficiency

We submit that the Code should include a single overall objective that can be used to reconcile the conflicting guidance of the subsidiary provisions. The incorporation of an overall objective would remove the ambiguity in the operation of the Code's current objectives and principles. An overall objective that is tightly specified to facilitate economically efficient outcomes would provide unambiguous and effective guidance to regulators in the process of decision-making.

The specified 'objectives' in other regulatory frameworks incorporate a wide-range of issues and elements. There are objects clauses that make specific reference to the importance of the consumer. For example in the Australian telecommunications industry, the object is:[82]

> (1) The object of this Part is to promote the long-term interests of end-users of carriage services or of services provided by means of carriage services.

Similarly, the objects clause relevant to the gas industry in the UK directs primary consideration to the impacts of decisions on consumers and includes reference to promoting effective competition:[83]

> (1) The principal objective of the Secretary of State and the Gas and Electricity Markets Authority (in this Act referred to as "the Authority") in carrying out their respective functions under this Part is to protect the interests of consumers in relation to gas conveyed through pipes, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas so conveyed.

The Commonwealth Government proposed that an appropriate objects clause for access regimes includes economic efficiency with references to competition and investment. In responding to the Commissions Part IIIA review, the Commonwealth Government proposed the following objects clause:[84]

> The object of this Part is to:

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82 *Trade Practices Act 1974*, Part XIC, section 152AB(1).

83 *UK Utilities Act 2000*,section 4AA(1).

84 Costello, P, *Government Response to Productivity Commission Report on the Review of the National Access Regime*, p.3, available at www.treasurer.gov.au/tsr/content/publications/NationalAccessRegime.asp.

(a) promote the economically efficient operation and use of, and investment in, essential infrastructure services, thereby promoting effective competition in upstream and downstream markets; and

(b) provide a framework and guiding principles to encourage a consistent approach to access regulation in each industry.

The adoption of an objects clause in the Code that is focused on economic efficiency would be consistent with supporting well-targeted decisions, increased certainty, consistency and accountability. Economic efficiency is not inconsistent with the elements of consumer protection, investment or competition, which have been incorporated into objects clauses in various regulatory regimes, including those outlined above. However, we consider that it is not obvious that the inclusion of these additional elements necessarily adds to an objective of economic efficiency and indeed the inclusion of these additional elements may be contrary to encouraging a consistent approach to access regulation. Thus, the incorporation into the Code of an overall objective with a primary focus on economic efficiency would meet the criteria established by the Commission for objectives clauses in its Part IIIA review.

Proposed recommendation

BHPB considers that the Commission should recommend the inclusion of an overall objective in the Code with a primary focus on achieving economic efficiency. The recommendation should be to:

- insert an overall objective into the Code, directing that the regulator's primary consideration in decision-making should be one of economic efficiency in the operation of gas pipelines and the pricing of pipeline services; and
- retain the relevant specific guidance on other matters (for example some of the issues specified in 2.24 or 8.1) as secondary or subsidiary principles.

Consistent with the process used to write and maintain the Code, any proposed changes should be subject to review, discussion and ultimately the agreement of all stakeholders prior to being implemented.

6.3 Appeal Rights

The right of independent review of decisions made by regulators, arbitrators and other government bodies is a common and expected feature in Australian institutions. Decisions made by gas industry regulators are no exception. BHPB endorses the need for effective appeal rights against decisions made by gas industry regulators. The potential for regulatory decisions to be the subject of public scrutiny by an independent appeal body provides strong motivation for regulatory agencies to fully consider facts and arguments presented, to act in accordance with the

requirements of the Law and the Code, to manage regulatory processes taking account of procedural fairness and to be transparent. These pressures on regulatory agencies support improved decision-making, which is of benefit to gas industry investors (including in upstream and downstream sectors) and consumers alike.

The provisions governing the right of appeal against a regulator's decision on an access arrangement contained in the Code and the Law have a number of strengths.

First, the appeal body is *only* able to consider matters that had been submitted to the regulator during the assessment of the access arrangement. This limits the ability for a service provider or user to hold back its most important arguments from the regulator during the access arrangements revisions process.

Second, the appeal process contains a number of reasonable constrains on the appeal that would promote a more efficient appeal process. These include the requirement to consider only matters already submitted (discussed above), a requirement on the appellant to set out its grounds in advance, a reasonable hurdle for the appellant to make out (s39(2)(a)), and a large discretion to the appeal body over how much of the appeal it will hear. In addition, the appeal body is not required to hear matters that it considers are trivial or vexatious (s38(11)).

Third, filing an appeal does not stop the new or revised access arrangement from coming into effect. It would be expected that. if the decision of the appeal body would require adjustment to prices in the regulator's decision, those adjustments would be given effect going forward. This prevents the appeal process being used as a means of delaying the implementation of the regulator's decision.

However, the very unusual trigger for an appeal on a review of an Access Arrangement implies that the appeal rights are asymmetrically weighted in favour of the service providers. This asymmetry between service providers and users means that the appeal mechanism is not as effective as it should be. Service providers have the right of appeal in all circumstances, while users right to appeal is limited.

Asymmetry of Appeal Rights

The asymmetry in appeal rights is related to the unusual — and non-transparent — process under the Code for going from a final decision to an approved Access Arrangement.[85]

[85] This provisions quoted refers to the process of assessing access arrangement revisions (that is, a review of an existing access arrangement). However, an identical process applies for the approval of a first access arrangement.

The most common avenue to conclusion of a final decision under the Code is that the regulator rejects the proposed access arrangement and requires the service provider to resubmit an amended arrangement.[86] After the final decision, the service provider has four options — and its choice determines whether users can appeal the regulator's decision. These options are as follows:

- option one — compliant revisions. Lodge revisions compliant with the final decision. These revisions are approved in the regulator's further final decision is made under section 2.41(a).
- option two — negotiate. Enter 'negotiations' with the regulator and submit revisions that, while not 100 per cent compliant with the requirements set out in the final decision, are considered by the regulator to 'substantially incorporate the amendments specified' and are thus accepted by the regulator. In this case, the regulator's further final decision is made under section 2.41(b).
- option three — submit non-compliant revisions. Lodge revisions that are non-compliant with the final decision. In this case, the regulator rejects the revisions under section 2.41(c) and drafts and approves its own further final revisions in accordance with section 2.42.
- option four — no revisions. Decide not to lodge revisions in response to the final decision. The regulator drafts and approves a further final decision under section 2.42.

The right for users to appeal against the regulator's decision only arises if the service provider chooses to pursue options three or four. Thus, if the service provider either accepts the final decision, or manages to negotiate a variation to the final decision that is acceptable to the regulator, then the right for a user to appeal is never triggered.[87]

Thus, if the service provider chooses to accept the regulator's final decision, users are effectively denied the right to appeal. The inevitable effect of the asymmetry of appeal rights is that regulators will place commensurately less weight on the arguments made by users especially in the final stages of the review. It is submitted that there is no sound rationale for this asymmetry of appeal rights. Indeed, the regulated entities are likely to be the most vocal participants in any review — and the more likely to be able to justify to their boards that appeal action be taken — already implies that regulators' decisions are likely to be asymmetrically biased in favour of the regulated entities. To go further and deny users a right of appeal adds to the structural bias against users.

Symmetric appeal rights support a greater likelihood of an efficient regulatory outcome. Further, in contrast to a court-based appeal, an administrative is a more feasible avenue for users and other interested parties to have a regulator's decision subject to independent review. The complexity and costs of court-based appeals,

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[86] This is a decision under section 2.38 (a)(ii).

[87] The reason for this is that section 2.48 only permits an appeal for any party where the regulator is required to 'draft and approve its own amended revisions' under section 2.42 (or section 2.45, which is not relevant to this discussion). This provides no barrier to a service provider lodging an appeal because it is within the service provider's power to require the regulator to 'draft and approve its own amended revisions'.

given the diffuse nature of any potential benefits, make court-based appeals a relatively unattractive option for users and most other interested third parties.

Transparency and timing of the appeal

As noted above, the Code does not allow for an administrative appeal until the regulator has made a 'further final decision' (and step after the final decision) — and even then, only if the service provider forces the regulator to draft and approve its own access arrangement revisions. In its Issues Paper, the Commission asked if the effectiveness and timeliness of the access arrangement approval process could be improved if appeals were permitted prior to the further final decision.

BHPB considers that efficiency of the process would be improved — and symmetry would be restored — if all parties were permitted to lodge an appeal after he final decision, that is:

- the regulator makes draft and final decisions in accordance with the current arrangements in the Code;
- following the release of the final decision, *all* parties have the right to lodge an administrative appeal;
- if an appeal takes place and is successful, the appeals body either writes its own decision or directs that the regulator amend its decision accordingly; and
- if no appeal is lodged, or the outcome of an appeal does not require changes to the regulator's final decision, then the final decision continues to operate.

An additional benefit of this process would be that it would remove one of the options noted above, which is the option for service providers to 'negotiate' changes to the regulator's final decision after it has been issued. The process for such negotiations lacks any sort of transparency and the outcome of the negotiation is not subject to independent review. In BHPB's view, the efficiency and timeliness of the decision making process would be improved considerably of the final decision were actually final — and appealable by all interested parties — and this additional, unintended, non-transparent and unaccountable step in the process were removed.

Proposed recommendations

BHPB considers that the Commission should recommend:

- changes to the Code that result in symmetric appeal rights for both owners and users of pipelines;
- changes to the Code that remove the scope for further private negotiation between the regulator and service provider after the final decision, by limiting the possible responses to a final decision: lodge an appeal against that decision or implement it; and
- changing the timing of appeals so that appeals may be lodged in response to a final decision.

6.4 Information Collection Powers

Introduction

The Code sets out a regulator's powers and service provider's obligations in relation to information in two areas:

- powers for the regulator to obtain information required to undertake prescribed functions, including approving access arrangement revisions. This is the main subject of our concern and is discussed below;
- the Information Package, referred to in section 5 *Information and Timelines for Negotiation*. This refers to information that service providers must make publicly available. The need to maintain the current arrangements is discussed at the end of this section.

Existing powers

The regulatory information collection provisions are contained in a number of sections of the Code and also in the Law:

- sections 2.6 and 2.7 of the Code refer to requirements relating to Access Arrangement Information. This is publicly available information. Section 2.8 is also relevant as it ensures that commercial-in-confidence information is not made publicly available.
- sections 4.1. 4.2, 4.3, 4.12 and 4.13 of the Code contain specific requirements related to the requirement to keep separate accounts, ability of regulators to specify guidelines about presentation of information and establish additional requirements for ring-fencing between related business entities, and directs the regulated business to comply with obligations under chapter 4 (thus including compliance with any regulatory guidelines and undertaking additional ring fencing) and to report to the regulator on its compliance.
- the Law section 41 (Schedule 1) contains provisions that allow regulators to gather information. These powers provide for the regulator to direct that information be given to it. As with the Code, the Law recognises that some information may be commercial-in-confidence and directs that regulators must not make such information publicly available (section 42, Schedule 1).

Regulator's need for robust, complete information

It is without debate that regulators require reliable and sufficient information in order to perform the functions required under the Code, and that regulated entities

have an incentive to not provide — and not even to keep — information that may assist the regulator to regulate.

With respect to the assessment of reference tariffs, regulators require information on the costs actually incurred in providing the regulated service. This requirement is independent of the approach to regulation that is adopted — that is, whether there is "rate of return" regulation, price caps with five yearly reviews using the building block approach, where price caps are used and the X factor is set using an estimate of total factor productivity, or where prices are set exclusively with reference to external benchmarks (which BHPB does not consider appropriate, as discussed in chapter 5).

Moreover, should regulators consider using alternative approaches to the building blocks approach to set the 'X factor' — like total factor productivity — the information on costs incurred and outputs provided will be required for all entities in the industry, on a continuous basis, and made publicly available. The extent of factors like vertical integration will also affect the level of information that regulators require. As discussed in chapter 5, where the distributor has a related party retailer — and even worse, an interest in one of the transmission pipelines supplying a market — the establishment of effective competition requires that distribution prices not be used to create barriers to entry, which can require detailed information to detect.

Service providers incentives to not provide information

As noted above, service provider's incentives are to *not provide* robust, complete information to the regulator. This is a substantial issue as the service provider is the primary source of information in the regulatory process.

The regulated business has an incentive to present information to the regulator supporting arguments that are financially advantageous to their business. This generally involves arguments that overstate costs. Thus, the regulated business has an incentive to *not* provide *complete information* to the regulator.

The regulated business has an incentive to *not maintain* particular types of information or to maintain information in a form that makes delineation between various business activities extremely difficult. This is particularly the case when a vertically integrated business entity conducts both regulated and unrelated activities.

The regulated business has an incentive to *change the way information is maintained* or recorded. Changing the format of information collection makes the task of the regulator more difficult. For example, being able to assess expenditure trends over time is extremely important in examining the validity of regulatory

proposals and even more important when developing incentive-based approaches to regulation.

The issues

Recent discussions on this issue in NGPAC have revealed that there is *ambiguity* as to whether the Code and Law provide the regulator with the ability to get the information that the regulator requires to do the job it is entrusted with.

While the Code provides the regulators with some power to issues guidelines on the information that service providers are required to keep during the regulatory period, there is ambiguity as to whether this power is adequate to address all of the matters that may be necessary. However, neither the Code nor the Law permit the regulator to require the regulated businesses to provide the prescribed information *during* the regulatory period.

Inability to specify the information required to be kept obviously would be a major concern; but the inability to gather information during the regulatory period is also highly undesirable.

Precluding the regulator from obtaining information until a review has commenced relies, amongst other things, on the regulated entities interpreting the guidelines as intended. This is a big hurdle for any type of accounting guidelines, but particularly for regulatory accounting guidelines given the obvious incentives of the service providers. Any difference in interpretation would not be evident until the commencement of the next access arrangement revisions process. Thus, allowing such a long delay before the regulator can receive the information is a high-risk approach.

Moreover, the inability to get information during the regulatory period would make it difficult for the regulator to ensure that the accounting guidelines are appropriate in the face of change — such as a change to corporate structures. A recent development is for regulated businesses to set up separate business units for construction and operation and to implement transfer pricing arrangements. The complexity of many corporate structures has also increased. Any issues for regulatory information need to be addressed at the time that the corporate changes occur, not at the time of an access arrangements review. Regulated entities are increasingly entering into. Regulators must have sufficient information gathering powers to ensure that they are able to ‘pierce the corporate veil’ to gain a complete understanding of ‘arms-length’ arrangements with regulated and related companies. This can only be achieved if the regulator’s information gathering powers enable them to require the relevant parties (not necessarily the regulated party) to maintain and provide certain information. This is not the case currently.

Regulatory decisions based on incomplete information or information that cannot be tested, lead to *sub-optimal regulatory decisions*. BHPB has previously identified the problem of regulators having inadequate information powers.[88] The inability of regulators to obtain complete and reliable information in a timely manner can contribute to delays in decision-making processes and increase uncertainty as debates arise around the existence of non-existence of certain information, the costs of gathering information, or the reliability of secondary sources of information and the appropriateness of using estimation and assumptions in the place of primary information.

Indeed, the current ambiguity in information collection powers has resulted in the Victorian Government introducing State specific information collection powers. The Essential Services Commission in Victoria, has additional information collection powers specified in gas distribution licences (see Box 6.2). Such a response does not promote nationally consistent in the gas industry regulation, and is of no assistance to consumers of gas outside of Victoria.

Box 6.2: ESC licence provision

PROVISION OF INFORMATION TO THE OFFICE (section 12, page 6)

"The Licensee must provide to the Office, in a manner and form and at a time decided by the Office and notified to the Licensee, such information as the Office may from time to time require. In addition (but without limitation) the Licensee must, promptly after being directed (pursuant to the Access Code) to do so by the Office, place on the Public Register (within the meaning of the Access Code) information specified in the relevant direction either concerning Reference Tariffs or information which constitutes, under the Access Code, access arrangement information with respect to the Access Arrangement, or concerning the derivation of the elements of such tariffs, such information or the Access Arrangement."

Moreover, BHPB does not consider that the arguments advanced by the service providers to limit regulators' powers in this area have any merit.

Service providers have argued that the provision of information is costly. For example, the AGA has stated:

> In periods of access pricing determinations, intrusion can also take the form of significant and costly information requirements, and the diversion of significant resources towards managing lengthy regulatory processes, rather than operating the business.[89]

However, as a regulated business, the cost of collecting and maintaining this information is part of the businesses operating expenditure and therefore is a cost

88 See BHPB submission to EMR.

89 AGA Submission to the Energy Market Review, *Key Issues for the Energy Market Review, Response to Issues Paper*, 19 April 2002, p. 6

ultimately borne by customers. Customers would welcome the small cost required for regulators to have access to complete, robust information — that is, the information required to do their job.

Regulated businesses have also argued that the release of information can be commercially damaging. This concern needs to be addressed on two levels. First, then issue at stake is not whether the information can released publicly — but whether the regulator can get it at all. Secondly, BHPB would question regardless whether the public release of information about a monopoly can cause it commercial damage. Irrespective, however, the Code and Law contain substantial limitations on the regulator's ability to release information obtained under a claim of confidentiality.

An implicit assumption in many of the service providers' arguments is that the receipt of information during a regulatory period may lead to regulators to intervene more in the operations of their businesses — or even to 're-visit' regulatory decisions. However, receiving information does not provide regulators with additional powers — merely the capacity to undertake the responsibilities entrusted to it under the Code.

Notwithstanding the problem of the ambiguity in the information collection powers set out above, BHPB's view is that regulators have been remiss in not fully utilising the powers provided in the Code and developing information collection guidelines. Nationally consistent guidelines have been developed by regulators to apply to the regulated sectors of the electricity industry. The existence of a national regulator (as discussed below) has the potential to simplify the development of these guidelines for the gas industry.

Proposed issues for recommendation

BHPB considers that the Commission should recommend that regulators develop and adopt nationally consistent guidelines for information collection, consistent with the current provisions of the Code as soon as possible.

BHPB considers that the Commission should recommend changes to the Code to ensure that ambiguity in regulator's information collection powers is removed and that regulators have powers that allow them to:

- prescribe the type and format of information that is to be maintained during an access arrangement period;
- require the regulated business to provide the prescribed information during the access arrangement period; or

- ensure that information requirements cover changes in the corporate structure of regulated businesses, that is changes to corporate structure do not limit the existence or availability of information required by the regulator.

Publicly available information

The regulatory decision making processes benefit from high levels of involvement of interested third parties, including small and large users. The availability of complete, robust information promotes transparency in decision-making supports the participation of interested third parties in regulatory processes.

The Information Package, in section 5 *Information and Timelines for Negotiation* refers to information relevant to obtaining access to services that the service provider must make publicly available. In most jurisdictions the information disclosure to users has been just adequate. It would be highly desirable for regulators to ensure that the maximum amount of information that can be made publicly with out harm to the service provider is made publicly available. This often requires judgement on the part of the regulator, as service provides initial position is that more information should remain confidential.

6.6 The need for a national regulator

BHPB has previously identified our concern about the lack of national consistency in energy market regulation.[90] Currently, the ACCC is responsible for regulation of gas transmission (except in WA), with jurisdiction specific regulators responsible for the regulation of gas distribution.

Even though all regulators administer the same law, different regulators inevitable develop different approaches to important matters. BHPB actively participates in regulatory processes and has made submissions to ACCC as the regulator of transmission pipelines, the ESC in Victoria, IPART in NSW, SAIPAR in SA and the ICRC in the ACT. To ensure that we engage effectively with the different regulators requires an on-going investment of resources to understand the particular approaches to issues. From a business perspective, there are no clear advantages in having State/Territory based regulation of pipelines, only costs in terms of additional effort and some uncertainty about outcomes.

Further, based on our experience of participating in or observing regulatory processes, we also consider there to be differences in the level of resourcing and expertise and in the motivation of different regulatory bodies. Such factors also

90 See BHPB submission to Energy Markets Review Issues Paper, p.2.

contribute to inconsistencies in both regulatory outcomes, as well as the propensity or vigour with which the Code is applied. The discussion of vertical integration in chapter 5 highlighted the differing capacity and propensity of regulators to do the job that is entrusted to them under the Code. We consider that combining the separate regulators into one would provide a greater scope to attract and maintain the staff most capable of performing the tasks required.

Accordingly, we endorse the creation of a single regulatory agency responsible for the economic regulation of gas pipelines (distribution and transmission) on a national basis. We accept that the most effective approach may be to establish a national energy regulator — as recommended in the recent Parer Review and endorsed by the Ministerial Council on Energy (MCE) [91,92] As currently proposed, the regulation of gas and electricity will be combined in the one body, the Australian Energy Regulator (AER). The effectiveness of the AER will depend in part on its ability to understand the important differences between the gas and electricity industries and the regulatory frameworks applying thereto. An organisational structure for the AER that recognised the differences between the electricity and gas industries would be one way of addressing this concern. Its effectiveness would also depend upon it being adequately resourced — that is, the capacity to retain expert staff, and to draw upon external specialist expertise as required. Finally, the MCE has proposed that the AER regulate gas transmission within 12 months. We support an extension to this proposed role, such that the AER's regulatory responsibilities include the regulation of gas distribution also.

Proposed issues for recommendation

BHPB considers that the Commission should recommend the establishment of a national gas industry regulator. The national regulator would be:

- the 'relevant regulator' for the purposes of the Code for transmission **and** distribution pipelines; and
- adequately resourced and include specialist staff with responsibility for managing gas industry issues.

91 Parer W. 2002, *Towards A Truly National And Efficient Energy Market*, Council of Australian Governments, Energy Market Review, p. 84.

92 Ministerial Council on Energy Communique, Sydney, 1 August 2003.

6.7 Code change arrangements

The Council of Australian Governments established the National Gas Pipelines Advisory Committee (NGPAC) on 7 November 1997, in the Natural Gas Pipelines Access Agreement to administer the Code. NGPAC is responsible for:

- monitoring, reviewing and reporting on the operation of the Gas Pipelines Access Law (including the Code);
- providing advice to the Ministers on interpretation and administration of the Gas Pipelines Access Law (including the Code);
- preparing information on the Gas Pipelines Access Law (including the Code) for general publication; and
- making recommendations on amendments to the Gas Pipelines Access Law (including the Code) to Ministers.

The process of developing Code change proposals presented to Ministers has *formal* involvement of all interested parties — governments, regulators, industry and customers (see Box 6.3). This is a key strength of NGPAC. It ensures that prior to voting on proposed amendments, the views of all parties are transparently presented to Ministers.

Box 6.3: NGPAC membership

NGPAC comprises an independent Chair and the Code Registrar, and representatives from the organizations indicated below:

- Commonwealth Government;
- State and Territory Governments;
- Australian Gas Association (AGA);
- Australian Petroleum Production and Exploration Association (APPEA);
- Australian Pipeline Industry Association (APIA);
- Business Council of Australia Energy Reform Taskforce (BCA ERTF);
- Australian Competition and Consumer Commission (ACCC);
- Two representatives of State and Territory based Regulators; and
- National Competition Council (NCC).

The Intergovernmental Agreement prescribes that only the government representatives are able to vote on Code change proposals. However, the report to Ministers from the NGPAC will set out a summary of the views of any member of the Committee who does not agree with the recommendation on the proposed amendment.

Source: The National Gas Pipelines Advisory Committee (NGPAC), 2000 *Information Booklet, Gas Pipelines Access Law including the Code 2000* available at www.coderegistrar.sa.gov.au.

Based on our involvement in NGPAC as the Australian Petroleum Production and Exploration Association representative, it is our observation that the effectiveness of the current structures in achieving Code changes has varied from relatively straightforward and effective to extremely lengthy process that delivers disappointing results. The difference in outcome appears to be related to the nature of the change being sought. When changes are 'mechanical' and therefore not contentious, the process works well. However, if proposed are associated with substantiative policy issues, the current structures do not work effectively. The long-running attempt by regulators to achieve a Code change to deliver improved information collection powers was an example of the process not working effectively. One of the 'missing ingredients' in being able to effectively achieve policy-based Code changes is the absence of strong policy support from Government representatives.

We note that the Parer Review recommended substantial change to the Code change process based on three main concerns:[93]

- few changes have been made to the Code;
- industry does not have a right to vote to approve or not approve proposed Code changes; and
- time taken to achieve a Code change.

To address these concerns, the Parer Review set out the following approach and recommendations:

> The Panel recommends formation of a Gas Advisory and Code Change Committee (GACCC) with two major functions:
>
> - proposing and progressing amendments to the Gas Code; and
> - providing strategic briefing to the MCE on natural gas market issues.
>
> The GACCC would be a committee consisting of no more than six members. Its members would be appointed on merit by the MCE and supported by a full time Commonwealth/state/territory funded and staffed Secretariat. The appointees would not be advocates for their particular industry sectors or organisations. The GACCC would appoint ad hoc Committees to assist in the development of Code change proposals or briefing assignments.
>
> The recommended Code change process would be broadly similar to that proposed for electricity, with the aim of avoiding unnecessary duplication of process. The Gas Code Change Secretariat would work with the GACCC to provide appropriate analytical support and assessment of proposals and forward them to the NER once the consultative process has been completed.

[93] Parer W. 2002, Towards A Truly National And Efficient Energy Market, Council of Australian Governments, Energy Market Review, p. 76-7.

> As a consequence of the formation of the GACCC and the move of the decision making function on Code changes to the NER, the National Gas Pipelines Advisory Committee, the Code Registrar and the Gas Policy Forum would be abolished.
>
> Amendment of the Gas Pipelines Access Law (and the related WA legislation) would be necessary for the new Code change process. [94]

BHPB has a number of concerns with the findings of the Parer review.

First, we submit that the relatively small number of changes to the Code is not an indicator that the Code change process necessarily has been ineffective, and note that this comment appears to reflect a confusion about the role of the Code to the National Electricity Code. The Code contains principles and processes, under which regulators make decisions. Such provisions are less likely to require change than say the highly prescriptive technical requirements contained in the National Electricity Code. As discussed above, in relation to the proposed mechanical changes to the Code, the process has worked well, and since 1997, there have been seven amending agreements resulting in 15 changes to the Code and/or the Law.

Secondly, BHPB is concerned that the implementation of the Parer Review recommendation on the Code change process would remove the key strength of the current Code change process — that is, the formal involvement of all parties. The proposed appointment and operation of the Committee potentially reduces transparency and facilitates informal lobbying of Committee members. This would be a backward step given that the current arrangements have formal processes for interested (but non-voting) parties to present their views in the existing Code change process. The proposed model also seems to introduce a substantial governance issue by giving the proposed National Electricity Regulator (NER) responsibility for both implementing the Code and approving or rejecting proposed Code changes.

An approach that retains the strengths of the current arrangements and addresses its weakness is to increase the level of policy support in the NGPAC process. This can be achieved by:

- placing an obligation on government representatives to engage in the work of NGPAC and provide high quality policy advice; and
- to increase the resourcing available to the NGPAC secretariat to allow greater use of independent advice. This could include the NGPAC Secretariat operating a separate Policy Group, including active participation of government representatives.

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[94] Parer W. 2002, 'Towards A Truly National And Efficient Energy Market, Council of Australian Governments', Energy Market Review, p. 92.

As noted above, to the extent that the Code change process has failed — which BHPB considers it has in relation to proposed changes that have a substantial policy dimension — the 'missing ingredient' has been the absence of strong policy support from government representatives.

Proposed recommendation

BHPB considers that the Commission should ensure any recommendations about the Code change process should preserve the strengths of the current system: this is formal involvement of relevant parties in Code change processes.

BHPB considers that the Commission should recommend that the current NGPAC structure be retained and that a separate Policy Group, including government representatives, be established. This is imperative that the continued evolution of the Code takes place based on consistently high quality policy advice and input. This Group should include industry and customer representatives, continuing the formal involvement of these parties in the development and operation of the Code, but preclude regulators to avoid inappropriate governance issues.

The Allen Consulting Group

Review of the Gas Code:

Commentary on Economic Issues

August, 2003

Report to BHPBilliton

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Suggested citation for this report:

The Allen Consulting Group 2003, Review of the Gas Code: Commentary on Economic Issues, report to BHPBilliton, August.

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Chapter 1

Introduction and Overview

1.1 Overview

The Allen Consulting Group was engaged by BHPBilliton to comment on a number of the issues relevant to the Productivity Commission's review of the Gas Access Regime. The Gas Access Regime comprises the National Third Party Access Code to Natural Gas Pipeline Systems (the Code), the Gas Pipelines Access Law (the Law) and the Natural Gas Pipelines Access Agreement (the Agreement).

The structure of this report – and the issues that are addressed – are as follows.

Chapter 2 discusses the rationale for regulation of the transportation elements that are in a position to exercise substantial market power. In this context, it is noted that the role of the Code (and Law and Agreement) is not confined solely to facilitating access of competitors into related markets, but is also directed to curtailing the ability for the owners of pipelines with substantial market power from charging inefficiently high prices.

This chapter also notes that while 'regulatory error' that may result in prices that are too low may generate inefficiency, error that results in prices that are too high have also have a substantial impact on efficiency – namely the reduction of both allocative and dynamic efficiency in related markets. The fact that much of the gas transported in Australia is an input into further production, and that even prices that deliver a normal return would imply a mark-up over marginal cost suggest that just the allocative efficiency losses from high prices could be substantial.

Lastly, this chapter discusses the concept of 'regulatory truncation of returns' that was accepted by the Commission in its review of Part IIIA of the Trade Practices Act 1974 (Part IIIA Review). It is noted that the theoretical possibility of such truncation is clear, and has been recognised by a number of Code regulators. However, the conditions under which any material truncation of returns is likely to result are quite strict – and are unlikely to be met for the vast bulk of the facilities whose prices are regulated under the Code, which are facilities that are in a position to exercise substantial market power, and so are very likely to be in a position where they are unable to set prices that recover the whole of their costs.

Chapter 3 addresses the appropriateness of the form of price regulation required (or permitted) under the Code, namely the use of price cap regulation where the 'building block' approach is used to set the X factor in the price cap – a more general requirement is that prices be set with reference to cost. A number of comments made in submissions and by the Commission in the context of the Part III Review are also analysed.

The conclusion reached is that price cap regulation is the most appropriate form of regulation for the assets regulated under the Code. It is also noted that, while productivity-based approaches may have some advantages over the building block approach for setting the X factor (the advantages flowing from a reduction in information asymmetry problems), the building block approach remains a robust means of determining price caps, and should continue to be used until productivity based measures are proved-up and demonstrated to be superior — importantly, productivity based measures are not the proverbial 'silver bullet'. In reaching this conclusion, many of the criticisms made of the 'building block approach' are found to be misdirected. The methodology for the revaluation of assets in the Code is also discussed, and it is concluded that the method employed — to set the regulatory value of existing assets at a point in time and then roll-forward this value from one period to the next in a certain manner — is probably the most important feature of the pricing principles in the Code.

Chapter 4 then discusses the adequacy of the overall guidance for regulators from the Code, including the objectives in the pricing principles section of the Code and the interaction with the other high-level guidance in the code (namely, section 2.24). Lastly, this chapter considers a further more technical issue that has been raised in recent matters, which is the extent to which the regulator's role can be characterised as selecting the best outcome for a particular matter, or whether it can only reject proposals considered to be outside of a reasonable range.

Chapter 5 then addresses a comment that has appeared in many of the submissions to the Part IIIA Review and the Parer Review, which is that regulators have set prices that are too low for the regulated businesses to provide the regulated services. Amongst other things, it has been claimed that regulators have adopted estimates of the cost of capital associated with the relevant regulated activities that are at the lower end of the feasible range, or have underappreciated the risk associated with the regulated activities.

Notwithstanding the emphasis with which such arguments have been made, little or nothing in the way of empirical support to date has been provided. In order to address this shortcoming in the debate, this chapter present an analysis of one source of empirical evidence that can be used to test this claim, which is the relationship between the market value of a regulated activity and its regulatory value. It is demonstrated that, if the regulator set price controls that compensated exactly for the cost of undertaking regulated activities (including the provision of a risk-adjusted return), then these values would be identical. In practice, however, it is found that the market value of regulated assets in Australia typically have exceeded their regulatory values by a substantial margin.

The conclusion reached is that no empirical support can be found for the view that the stance of regulators provides a threat to new investment in these activities, that regulators are 'too ambitious' when setting regulated charges, or that regulators consistently adopt forecasts that are biased towards the interests of the customers. Indeed, the more plausible conclusion that can be drawn from this analysis, is that the regulators systematically err in favour of providing regulated entities with a return that exceeds the cost of capital associated with the regulated activities.

1.2 An introductory remark

As a number of stakeholders will inform the Commission, the Code (and Law and Agreement) were developed with the substantial of a large number of industry participants, and with large concessions made by all industry stakeholders. Indeed, the introduction of the Code was welcomed by all of the relevant industry associations at the time.

At the time, there was widespread agreement that creating competition in markets where this was previously non-existent – and the protection against the exercise of market power – would require a regulatory regime like that set out in the Code. There was also widespread agreement that it was in the combined interests of all market participants to have a set of regulatory arrangements that specified in more detail the requirements of the relevant parties and the powers of the regulator. The associations representing the transmission and distribution associations accepted that regulation based upon cost was inevitable. What they got in return was a regime that would set a benchmark for due process and the independence of regulatory decision making, including strong rights of legal and administrative appeal and clearly articulated principles so that appeals are meaningful.

Of course, a regime that was developed by a committee can always be improved upon. Moreover, in the time since the Code was conceived, Australia's experience with economic regulation has expanded considerably. The face and structure of the industry has also undergone a substantial metamorphosis, which has probably exceeded anyone's expectation at the time that reforms to the natural gas industry were first proposed. Thus, we consider that the Commission's review provides a very useful opportunity to stand back and assess how the regulatory regime under the Code has performed during to date, to recognise its strengths, and to ask where its effectiveness can be enhanced.

However, in order to permit such improvement, it is imperative that the Commission get to the source of any apparent failing of the Code. Inevitably – or unfortunately – the success or otherwise of much regulation lies in the detail of the regime. We have emphasised above that resort to objective evidence is essential, given the strong commercial interests of the parties with a stake in the Commission's review. It is also imperative that the Commission look beyond statements like 'intrusive', 'heavy-handed', 'light-handed' and 'prescriptive' — while often of high theatrical quality, such statements inevitably are defined only in the mind of the individual and have little in the way of analytical content. This is not to say that all industry concern with the Code is necessarily without merit — just that the analysis needs to be undertaken.

It is also important that the Commission recognised the often delicate trade-offs that exist in the design of any regulatory regime, and which are reflected in the design of the Code. Less prescription or more flexibility also means less certainty. Greater efficiency of the regulatory process and consistency across decisions also means a reduction in the due process awarded to all stakeholders, and a reduction in the right of each individual service provider to have its own case considered on its merits.

In addition, when considering alternative forms of regulation for the natural gas industry, it is important for the Commission to draw upon not only the experience in Australia, but of the reforms to and regulation of the natural gas industry — and other similar utility industries — in other countries. The only thing remarkable about the model for reform that was introduced into the Australia natural gas industry is how unremarkable those reforms have been. The introduction of competition in upstream and downstream related markets and the pro-competitive regulation of the natural monopoly transportation components has been the standard model introduced in many developed — and even several less-developed — countries. Similarly, price cap regulation not too dissimilar to that practiced in Australia has precedents in many other countries. Precedents when designing regulation are important; regulation is practical not theoretical.

Lastly, any inferences for the efficiency of the Code from the decisions made to date need to take account of the special nature of the first round of decisions under the Code. Many of the elements of access arrangements that have been controversial in the first round would be expected to uncontentious in the future. The regulatory value assigned to the existing assets — which has probably been the most contentious of all issues in the first round — is set and locked-in in the first review.[1] Many of the other elements in an access arrangement — the terms and conditions, capacity trading policies etc — would also be expected to remain unchanged at future reviews, at least in the absence of a reason for change. Thus, it would be expected that both the workload and priorities for regulators would change in their subsequent reviews, as would the expertise of regulators. Observations about the focus, timeliness or cost of the first round reviews need to take the special nature of the first round reviews into account.

[1] The merits of the Code's principles for asset valuation are discussed in Chapter 2.

Chapter 2

Rationale for Regulation and Truncation

2.1 Why Regulate?

The efficient provision of infrastructure services is a critical contributor to Australia's economic well-being. This was recognised several years ago by the then Chairman of the National Competition Council, now Chairman of the ACCC, Graeme Samuel, who noted that

> … Infrastructure sectors such as energy supply, transportation, communications and water supply play a pivotal role in the Australian economy. They generate major business inputs, representing between 7 and 16 per cent of production costs for most Australian industries and also provide essential services to the community. Any inefficiencies in infrastructure provision directly impact on Australia's growth, competitiveness, and ultimately on living standards. [Samuel 1998]

This economic importance of infrastructure industries, including the gas pipeline industry, is not of course a reason in itself to regulate them. Many industries are important, but very few are regulated. Regulation of gas pipelines occurs because of their particular economic characteristics: they are natural monopolies.

Natural monopolies are defined as those industries whose output is produced at least cost by just one firm.[2] In these circumstances, it is socially desirable for all the output of the industry to be produced by a single producer. However, this creates a policy dilemma, which is how to stop that single producer from setting monopoly prices, to the detriment of buyers in the market and society as a whole.

Regulators of gas pipelines in Australia (and elsewhere) have resolved this dilemma by regulating prices in a way which enables the owners of the natural monopoly to obtain a competitive return on their capital, adjusted for the risks they face. Following modern practice, regulators also provide gas pipeline firms with incentives to improve their operating efficiencies.

It should be noted that it is generally only natural monopolies that are subject to price regulation. Monopolies that are not natural monopolies are not usually regulated, because there exists a presumption that if a monopolist uses its market power to raise its prices and obtain monopoly profits, other firms could enter the industry and undercut the price charged by the monopolist, and so compete away the monopoly profit. Section 46 of the Trade Practices Act aims, *inter alia*, to protect these potential entrants from the misuse of market power by the monopolist, where misuse of market power broadly means conduct which damages the competitive process.[3]

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[2] Natural monopolies are often loosely associated with economies of scale in production i.e. because of high levels of fixed cost, average costs of production decline with increases in output. Strictly speaking, with a single product firm, economies of scale are sufficient but not necessary for the existence of a natural monopoly, and when firms produce multiple outputs, economies of scale are neither necessary nor sufficient for the existence of a natural monopoly. However, as it happens, gas pipelines are natural monopolies which exhibit significant economies of scale.

[3] During the course of the inquiry into the National Access Regime, several participants put forward the view that s.46 could be used to address access regulation. Quite rightly, this proposition did not receive the support of the Commission in its Inquiry Report. Without readdressing all the issues raised in that debate, it is worth pointing out that s.46 does not prohibit a monopolist from charging monopoly prices.

In the case of natural monopolies, however, there can be no presumption that entrants can or would enter the market to compete away any monopoly profits. First, by definition, it would be socially undesirable for second or subsequent firms to enter the market, because production in a natural monopoly industry is most efficiently carried out by just one firm. Second, incumbent natural monopolists would more than likely be operating at a significant cost advantage compared to new entrants, because they would have exploited economies of scale. Thirdly, much of the cost incurred by a new entrant pipeline would be economically (as well as literally) sunk — that is, having little value in an alternative use. Thus, a new entrant's capital would be lost if it entered the gas pipeline market and discovered that it could not operate profitably because, say, of strategic pricing behaviour by the incumbent pipeline owner. Hence, the only way to stop a natural monopolist from using its market power is to regulate it.

A reasonable question to ask, however, is whether the natural monopoly characteristics of a particular pipeline will hold over the long term. In its Review of the National Access Regime, the Productivity Commission stated that increases in demand may render a market contestable even without changes in the cost structures at the firm level (final report, p41). In other words, the natural monopoly would be unsustainable. This is, presumably, what the Institute of Public Affairs had in mind when it submitted

> … most … monopolies are short-lived since if they extract high prices this rapidly attracts competition (quoted in PC report, p40)

However, for this to happen, economies of scale would have to be exhausted and the natural monopoly would be operating at decreasing returns to scale. While in theory this may occur in some industries, it is less likely to occur with gas pipelines.

For gas pipelines, there are substantial economies of scale in constructing a new pipeline. This derives from the fact that the quantity of steel required (and hence cost) rises proportionally to the radius of the pipeline, but the volume rises proportionally to the square of its radius. The normal relationship between output and cost after a pipeline has been constructed is as follows.

- The incremental cost associated with the next increments to capacity is typically very low — as capacity can be increased substantially through the addition of low-cost compression.
- However, the incremental cost associated with the addition of further compressors tends to rise because the impact of additional compression on capacity declines with the additions. Eventually, further capacity can only be added by duplicating sections of the pipeline (which is referred to as looping). However, while the incremental cost of adding capacity through looping is higher than compression, the average cost of providing supply typically continues to fall.

Thus it does not address the fundamental rationale for the regulation of natural monopolies. It is also notable that one of the participants that most strongly urged the use of s.46 to address access issues, the Institute of Public Affairs, subsequently advocated the weakening of s.46, in its submission to the Dawson inquiry into the competition provisions of the TPA.

Thus, the average cost of an optimally sized pipeline falls significantly with the level of output delivered. In addition, as demand increases over time, the average cost of providing supply would continue to fall substantially for a period (that is, while capacity can be added through compression) but continues to fall thereafter (at a slower rate) as demand increases and additional capacity is added through looping.

The implication is that even given the fact that pipelines are constructed incrementally, the average cost of supply would be expected to fall with the level of output served, and so the natural monopoly technology of gas pipelines would be expected to be sustained.

2.2 Role of the Gas Code – Access Regulation or Price Control Regulation?

An issue the Commission addressed in its Part IIIA report was whether it was efficient for access regimes to perform the dual roles of *access regulation* and *price control regulation*. In this context, access regulation is used to refer to regulation whose objective is to address an essential facility owner's possible incentives to deny third parties the use of (or access to) its facility, whereas price control regulation refers to regulation whose objective is to control the prices that can be charged for the use of that infrastructure where the owner has substantial market power.

The Gas Code is intended to perform the dual roles of *access regulation* and *price control regulation*. Prior to the introduction of the Gas Code, the prices for delivered gas were regulated in some form in most Australian jurisdictions, albeit often not transparently, nor under specific legislation that provided the ability for appeal. Most of those previous regulatory price controls have now been removed — in some jurisdictions the controls have been removed implicitly as a result of the privatisation of formerly government-owned utilities, and the associated loss of direction of price setting as a price control option. The remaining controls on final (retail) prices are largely limited to small customers and intended only to apply for a transitional period prior to the establishment of effective competition amongst retailers.[4] Accordingly, absent the reintroduction of price controls on retail prices, it should be expected that, in the future, the only regulation on final prices will occur through the regulation of the transportation component (in cases where that component is in a position to exercise substantial market power).

We do not consider that it would be either efficient or practicable to seek to reduce the role of the Gas Code to addressing concerns only about the denial of access and to address concerns about monopoly pricing through alternative instruments.

- First, we agree with the comments made in a number of submissions to the Part IIIA review that access denials and monopoly pricing can be very hard to distinguish where there are vertical linkages between the owner of the bottleneck infrastructure and a participant in the downstream market, and even hard to untangle where ownership of the different functions is separate. Accordingly, a large degree of overlap between the different regulatory roles would be expected.

[4] The transitional role of retail price controls applies only in jurisdictions that have committed to introduce full retail contestability.

- Secondly, where the owner of the bottleneck facility is independent of the downstream market participants (which is the case in a number of situations), the effective regulation of final prices would require regulation of the prices charged by the bottleneck facility component.
- Thirdly, to the extent that monopoly price regulation were achieved by regulating final prices, this would imply that an additional function in the supply chain would be regulated over the alternative of just regulating the price of the essential facility input. An implication would be that it would reduce the scope of competition to discipline the behaviour of retailers. It is noted that retailers have an important role in gas markets — knowing their customers' requirements, they sign contracts for gas transportation capacity and gas commodity, and so provide signals to upstream participants about future requirements. Retailers also design prices for final customers, and therefore have the role of developing price offerings to pass-through cost structures into final price structures (and so encourage greater efficiency of use).[5]

A feature of some submissions to both the Commission's Review of the National Access Regime and the Parer Review was the view that the regulation of gas pipelines has (somehow) perverted the original intent of the Hilmer report, which argued for 'light-handed regulation' (though this term is rarely defined by those who use it). With this in mind, it is worth recalling the words of the *Transmission Working Group Report to the Gas Reform Taskforce*, which reported in October 1995, just two years after Hilmer, and before the Code was drafted. According to this report (p5):

> The justification for regulation of transmission pipelines arises in response to two interrelated concerns:
>
> 1. Pipelines often have strong monopoly power (except where faced with pipeline competition or the threat of by-pass) that provides them with ability to extract unreasonable returns from shippers, and thus impede the growth of the gas industry.
> 2. Where the pipeline owner/operator has interests in upstream or downstream markets it may act to prevent or impede the entry of a competitor into that market by charging discriminatory tariffs or by erecting non-price barriers
>
> - This problem would be a particular concern where there is a monopoly or near monopoly in a related market, and where the pipeline company tried completely to block entry into that market
> - There could still be a problem, however, where the pipeline operator only has relatively small interests in related markets — as it may have the incentive to tilt the playing field to discriminate against certain new entrants (i.e. ones that would compete in the same area as the pipeline business' related interest).
>
> The Working Group considers that the prevention of monopoly pricing by transmission pipelines is of particular importance given the significance of transmission pipelines in the gas supply chain in Australia.

[5] It is noted that competition retailers will only force retailers to pass-through the cost structure implied in the prices that they pay for the use of the essential facility infrastructure, rather than the actual cost structure of the essential facility. However, it is common practice for gas transmission pipelines to set prices based upon capacity (rather than linear prices), and for distributors to set non-linear tariffs that reflect the customers served. Both of these practices provide scope for the prices paid by a retailer for transportation to reflect the cost associated with those elements of the supply chain.

Thus, from the outset, the prevention of the exercise of monopoly power was a key objective of pipeline regulation. It is difficult to sustain an argument that regulators have assigned to themselves a more interventionist role than was originally envisaged.

2.3 Issues Arising in the Review of the National Access Regime

The Productivity Commission's report of September 2001, *Review of the National Access Regime*, examined the access arrangements established under Clause 6 of the Competition Principles Agreement and Part IIIA of the *Trade Practices Act 1974*. Since the National Gas Code has been certified under Part IIIA, the general issues canvassed in that review are relevant to the Review of the Gas of the Access Regime. Indeed, examples from the gas industry were used on several occasions by participants in the review of the national access regime, including by the Commission in its Inquiry Report.

This section discusses some of the substantive economic issues raised by the Commission in review of the national access regime. A general theme from this section is that some of the Commission's findings and recommendations, about access to, and regulation of, infrastructure, whatever their general merits, do not carry over to the particular case of gas.

The Importance of Allocative Efficiency

During the review of the national access regime, a number of parties asserted that the infrastructure regulatory regime is inhibiting investment — including in gas pipelines. The argument was that over-active regulators, in their efforts to 'surgically' remove monopoly rents, in fact go too far and under-reward the owners of infrastructure, given the costs they occur in the provision of infrastructure services and the risks they face.

The archetype of this view, quoted by the Commission in the Part IIIA Review,[6] was expressed by Epic Energy, in commenting on the ACCC's decision on the regulated return for the Moomba to Adelaide pipeline:

> The downward trend in the allowed rate of return on investment and tariffs can only create uncertainty in the investment community. This, coupled with the micromanagement and the intrusive approach taken by the ACCC, will act to distort future decisions on whether to invest in future infrastructure.

Energex, in its submission to the review argued that the current approach to access regulation stifles innovation:[7]

> … there will be no dynamic efficiency or technical progress in the sorts of models currently employed in Australia. The Schumpetarian argument is that it is only the opportunity of higher returns than the perfectly competitive rate which will induce firms to undertake risky and uncertain investment and innovational activities that offer the prospects of enhanced services to customers at lower prices than otherwise. … This opportunity does not exist in the simple neo-classical perfectly competitive model applied by Australian regulators where ex post rates of return are imposed ex ante.

A somewhat more analytical tone was adopted by the NECG in one of its many submissions to the review:[8]

[6] Part IIIA report, p67.

[7] Part IIIA Report, p67.

> In using their discretion, regulators effectively face a choice between (i) erring on the side of lower access prices and seeking to ensure they remove any potential for monopoly rents and the consequent allocative inefficiencies from the system; or (ii) allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent dynamic efficiencies such investment engenders.
>
> There are strong economic reasons in many regulated industries to place particular emphasis on ensuring the incentives are maintained for efficient investment and for continued productivity increases. The dynamic and productive efficiency costs associated with distorted investment incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing.

The NECG illustrated this claim with a diagram which purported to show that the welfare loss due to regulatory underpricing is "significantly greater" than the welfare loss due to monopoly, where a monopolist sets a price that is as far above the competitive equilibrium price as a regulated price is below it.[9]

In its Inquiry Report, the Commission did not accept the view that there exists a choice between incurring allocative efficiency costs due to over-compensation and dynamic efficiency costs due to under-compensation. This was because both types of errors are likely to influence investment outcomes and so have dynamic efficiency implications. However, the Commission did conclude that there is a potential asymmetry of effects, in that over-compensation could lead to inefficiencies in the timing of new investment (it is made too early), while under-compensation could lead to major investments being foregone totally. According to the Commission, the latter is likely to be a worse outcome; hence 'regulators should be circumspect in their attempts to remove monopoly rents perceived to attach to successful infrastructure projects'.

It is a factual question whether regulators of gas infrastructure have or have not under-compensated infrastructure owners for the costs incurred (including for the risk borne), and some empirical evidence of this proposition is presented in Chapter 5. However, factual matters aside, it is important that the Commission appreciate fully the allocative efficiency losses that typically arise from monopoly pricing of infrastructure services.

This is because, as acknowledged by virtually all participants in these debates, infrastructure assets are nearly all natural monopolies. Indeed, it is because they are natural monopolies that their prices are regulated at all. Natural monopolies are characterised by having large fixed (and sunk) costs, compared to their marginal costs. This is certainly true of gas pipelines, and this means that the first-best competitive solution, which is to set price equal to short run marginal cost, is not feasible because this would not enable revenues to equal total costs (including a return on capital). To solve this problem, prices are set above marginal costs, in a variety of different ways. (For example, prices can be set as multi part tariffs with a fixed component.)

Regulators of natural monopoly infrastructure assets aim to return to the owners of those assets sufficient revenue for them to earn a competitive, risk-adjusted, rate of return. Because prices must be set above marginal cost to recover total costs, inevitably, some allocative inefficiency will result.[10]

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8 Part IIIA Report, p83.

9 NECG, page 23 of its Submission of 18 January 2001.

10 Regulators should set prices which minimise this allocative efficiency, or provide incentives so that the natural monopolist chooses a set of inefficiency-minimising prices

An important consequence of the inevitability of some allocative inefficiency in a natural monopoly, is that the exercise of monopoly power to further increase prices (or, equally, overcompensation by a regulator) would lead to the creation of significantly more allocative inefficiency. Critically, this allocative inefficiency is much larger than that which results from having prices set just sufficiently above marginal cost for asset owners to earn a competitive return on their capital.

This can be seen in Figures 1 and 2 below.

Figure 1 shows the case of price being set above marginal cost in a competitive industry. The loss of efficiency (also known as the deadweight loss) is shown by triangle Z. The efficiency loss, as drawn, is small.

However, this case cannot apply to natural gas pipelines, because they are natural monopolies. As discussed above, in this instance, price must be set above marginal cost in order for the owners of natural monopolies to earn a competitive return on their capital. This is shown in Figure 2, where the regulated price Pr is set above the price that would be attained in a competitive market, Pc. At the price Pr, the natural monopolist earns a competitive return on capital. This produces an efficiency loss denoted by the triangle A.

Suppose price is set above Pr, to Pr1. In this case, the resultant additional loss of allocative efficiency is denoted as not just the triangle Z but the triangle Z plus the much bigger rectangle B. This is so even though the increase in price, and decrease in quantity purchased, is the same as the case shown in Figure 1. In Figure 2, the loss of allocative efficiency is comprised of two parts. These are the loss of consumer surplus (Z) associated with the rise in price from Pr to Pr1, and the reduction in quantity purchased from Qr to Qr1; and the loss of consumer surplus (B) associated with the reduction in quantity purchased from Qr to Qr1, at the old price Pr.

The second part of the loss arises because the starting point is a price that is already distorted. This is just another example of the well known result from microeconomic theory that the efficiency loss from a distorted price (i.e. a price above marginal cost) will be proportional to the square of the distortion. The efficiency loss from over compensating a natural monopolist will therefore be much higher than the efficiency loss that would arise from an equal sized over compensation to a firm in a competitive industry.

Figure 1

DEADWEIGHT LOSS WITH NO PRE-EXISTING ALLOCATIVE INEFFICIENCY

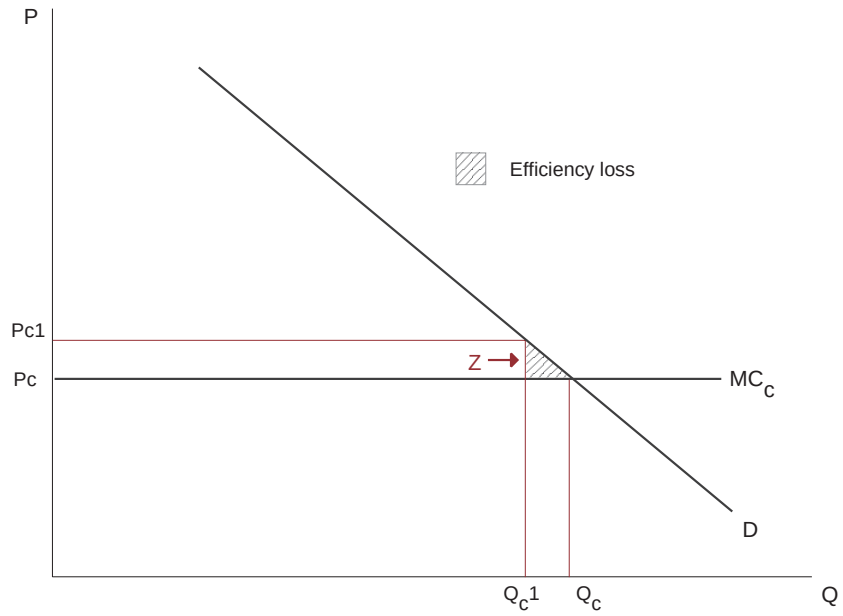
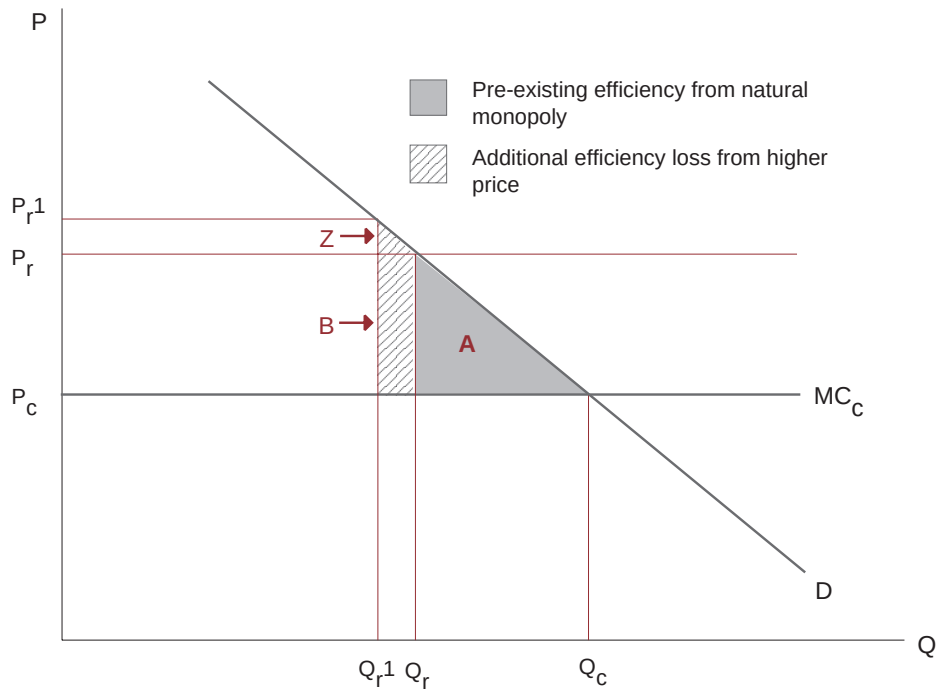


Figure 2

DEADWEIGHT LOSS UNDER NATURAL MONOPOLY



The above analysis was framed as one where the natural monopoly must set price to recover total costs, a large proportion of which is fixed costs. In the long run, all costs are variable. In general, long run average costs might be increasing, decreasing, or unchanged as the quantity produced changes. The answer depends on the particular technologies that are used in the industry under analysis.

However, as discussed above, for gas pipelines, economies of scale (i.e. declining average costs) tend to hold even in the long run, and the incremental cost of the next additions to capacity (which can more than double initial free-flow capacity) are typically very low. Thus, the allocative efficiency losses associated with regulators overcompensating natural monopolies — that is, allowing them to charge a price above that which allows them to earn a competitive return on their capital — will be much larger than if competitive firms were (somehow) to charge a price which exceeded the competitive equilibrium price by the same amount.

In summary, a correct analysis of over-compensating gas pipeline owners must take account of the fact that, because pipelines are natural monopolies, the return of sufficient revenue that gives those owners a competitive, risk adjusted, return on their capital will inevitably involve a pricing structure that must imply some allocative inefficiency. Over-compensating the owners of pipelines, that is, allowing even higher prices, will lead to significantly further deteriorations of allocative efficiency.

The Importance of Productive and Dynamic Efficiency for Buyers

In its report on the National Access regime, the Commission placed particular weight on the effect of under-compensation or over-compensation on investment in essential infrastructure. The Commission concluded that under-compensation is likely to lead to worse dynamic efficiency outcomes than over-compensation. However, this is only a partial analysis. It can be just as well argued, that over-compensation of infrastructure owners will harm the dynamic efficiency of industrial users of pipeline services, as well as their productive efficiency, because they will have to pay an inflated price for those services.

For example, an industrial user of pipeline services might be considering an investment in a plant which requires gas as a major input. A high price for pipeline services could be sufficient to defer or deter that investment. If so, the welfare losses associated with under-investment in infrastructure in investment, caused by under-compensation to infrastructure owners, could occur in other industries in which gas is an essential input.

In many industries, gas is a very important input. For example, a paper mill would typically use more than 500 TJ of gas per year; a hospital would use 100-499 TJ per year; a large commercial company would use 10-99 TJ per year; and a small commercial company would use 5-9 TJ per year. In aggregate, commercial and industrial users constitute the nearly 90 per cent of gas consumption. In 2000/01, total gas consumption was 975.39 PJ[11], which was divided as

- Residential 121.6 PJ;
- Commercial 50.1 PJ;
- Electricity generation 225.59 PJ;
- Manufacturing 393.25 PJ
- Mining 151.1 PJ

with the remainder coming from sectors like agriculture and construction.

[11] Between 1990/91 and 2000/01, consumption of gas in total grew by about 50 per cent.

Higher gas prices would not only impact on the productive efficiency of these businesses, but could aversely impact on their investment decisions.

Just as with investment in pipelines, direct evidence on these questions is difficult to ascertain, because nobody knows what the counterfactual to the regulated outcome, that is actually observed, would look like. However, there should be no *a priori* presumption that over-compensation is likely to lead to worse dynamic and productive efficiency losses *for the economy as a whole* than under-compensation.

2.4 Truncated Returns and Investment

What is the issue?

An issue which occupied much of the Commission's attention in the review of the national access regime was the possibility that regulation might lead to the 'truncation' of returns, and so deter investment.[12]

> It is also important to recognise that some non-contestable investments undertaken by incumbent service providers may be of a marginal nature. That is, while incumbency may sometimes provide an opportunity to delay re-investment to generate monopoly rents, demand and cost conditions might equally mean that an incumbent will undertake projects that are only expected to return their risk-adjusted cost of capital. Again, such projects are likely to be deterred by the prospect of regulatory truncation of balancing upside returns if a venture in fact proves to be more successful.

The Commission's Issues Paper also noted the potential for access regulation to result in inefficient levels of investment if regulation 'asymmetrically truncates the distribution of expected returns from investment'.[13]

A numerical example of the truncation was provided by King and Gans,[14] as follows. Suppose a cable network costs $51m to install. If Pay TV services on this network are successful (that is, demand for these services is high), the firm receives $100m in revenue. If they are moderately successful, the firm receives $60m and if they are unsuccessful, the firm receives $20m. If the probabilities of these outcomes are 25 per cent, 50 per cent and 25 per cent, respectively, then the expected revenue to the firm is $60m, and the expected profit is $9m ($60m of revenue less $51m of cost). Because the expected profit is positive, a risk neutral (or moderately risk averse) firm will make the investment.

Suppose now that the Pay TV services become subject to regulated access. A potential access seeker will wait and see whether demand for Pay TV services is high before deciding to enter. Suppose that demand is high, and so the access seeker enters the market and competes with the incumbent firm. As a result of this competition, the incumbent firm receives only $60m is revenue. *Ex post*, profit to the incumbent firm is $9m. However, the *ex ante* expected revenue is just $50m (0.25*$20m + 0.5*$60m + 0.25*$60m) leaving an expected loss of $1m. Hence, if the incumbent firm believes that its infrastructure will be subject to regulated access after it is built, the investment will not be undertaken in the first place. In this example, the problem has been caused because, with regulated access, the high demand return has been truncated from $100m to $60m.

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12 Part IIIA Report, p.281.

13 Productivity Commission, Issues Paper, p.20.

14 King, S, J. Gans, 2003, 'Access Holidays or Network Infrastructure', *Agenda*, Vol 10, No.2, pp.163-178.

The Commission analysed a number of solutions to the truncation problem, including

- 'binding rulings', given prior to investment, that services provided by a proposed facility would not meet an access regime's coverage/declaration criteria;
- 'framework undertakings', which would be agreed between the service provider and regulator prior to investment, covering access terms and conditions;
- higher rates of return for risky projects;
- access holidays or similar time-based exemptions from coverage under an access regime; and
- profit sharing arrangements.

After consideration of all of these options, the Commission recommended that Part IIIA should make provision for binding rulings on whether an infrastructure facility would meet the declaration criteria. It also recommended that where a license to construct and operate a government sponsored essential infrastructure facility is to be awarded following a competitive tender, there should be a provision in Part IIIA to provide that the services concerned be immune from declaration.

One of the proposed solutions to the truncation problem that attracted a lot of attention was the idea of an access holiday (that is, a regulation-free period of time when the infrastructure owner is free to make monopoly profits). Opinions on the benefits of access holidays were mixed, with some stakeholders saying they are unnecessary, while at the other extreme, Duke Energy submitted that what it wanted was a permanent holiday:

> With respect to holidays, DEI does not consider them to be a solution to the regulatory risk associated with new projects unless they are in effect a perpetual null undertaking (that is, for the life of the asset). Anything less than a perpetual holiday will mean that the service provider remains uncovered early in the assets life while the majority of the project risks are being resolved and will be covered at a time when the project may be reaching its potential.

Ultimately the Commission did not recommend the adoption of access holidays; however the Parer Review did recommend 15 year holidays for gas pipelines.

Assessment

It should be noted that the truncation issue arises only in very special cases, that is, when the variance of *ex ante* returns is large. In the King and Gans numerical example discussed earlier, suppose that the possible revenues are {$50m, $60m, $70m}, instead of {$20m, $60m, $100m}. The *ex ante* expected value of revenue without access regulation is $60m (as per the previous example). If the high return is truncated to $60m with access regulation, as previously, the *ex ante* expected value of revenue becomes $57.5m, this time above the $51m cost of the infrastructure. Despite the truncation of revenue due to regulation, the project is still profitable *ex ante*, and so would go ahead.

The question of whether and how regulation-induced truncated returns will affect investment thus turns on whether a project has a high upside (which could be truncated by regulation) and a low downside (which would depress the ex ante value of profits). Thus, the essential problem of 'truncation' is that the distribution of possible future returns is wide — and more particularly, that there is a material probability that the service provider may not be able to set prices that recover its revenue requirement at some time in the future.

While there may be infrastructure assets which exhibit these characteristics, most of the facilities that are regulated under the Code are unlikely to be among them. Many of the gas assets that are regulated under the Code are distribution businesses, where both the upside and downside potential of revenues is low. Moreover, most of the transmission pipelines that are regulated have much of their capacity tied up under long term, fixed commitment contracts, some of which may have been signed prior to the investment taking place. In both of these cases, the *ex ante* demand risk facing the pipeline owner/investor — and the potential for 'blue sky' — is low.

Thus, while we do not dismiss the importance of ensuring that the Code not impede efficient 'greenfields' projects, we consider it important to distinguish carefully between these projects and the more typical of projects that are regulated under the Code when considering any changes to the form of regulation that is applied by the Code.

Chapter 3

Form of Price Regulation

3.1 Introduction

The purpose of this chapter is to comment on a number of issues associated with the form of price regulation that is practiced or permitted under the Code. While the pricing principles in section 8 of the Code address many matters, some of the key features can be summarised as follows:[15]

- reference tariffs should be set such that service providers expect to recover the efficient cost incurred in providing the service — that is, prices should be set with reference to cost;[16]
- the meaning of cost in section 8 is either the actual cost incurred or the cost that is forecast to be incurred by the service provider (subject to tests of the 'prudence' of that expenditure), rather than a cost that may be predicted from an econometric model ('benchmark' approaches);[17]
- the use of price cap regulation is encouraged (and the universal approach by regulators under the Code),[18] under which prices are decoupled from costs for a period in order to provide an incentive for productive efficiency, and regulators are encouraged to draw on such incentives when assessing matters such as whether expenditure will be, or has been, prudent;[19]
- the mechanism under the Code for implementing price cap regulation has come to be termed the 'building block' approach, by which the prices are reset in line with cost at the beginning of a regulatory period, and the real rate of change in prices (the X factor) is set with reference to forecasts of the service provider's expenditure requirements for the regulatory period;[20] and

[15] The Code also includes a number of principles designed to ensure efficient pricing. These include section 8.16(b)(i) in combination with sections 8.25-8.27, which have the effect of requiring that the users of a new facility expect to pay at least the incremental cost associated with the facility, and sections 8.38-8.42, which place bounds around the cost allocation reflected in the reference tariffs.

[16] The italicised explanation for section 8 of the Code states that the overarching requirement of section 8 is that, when reference tariffs be set or reviewed, they reflect the efficient cost (or anticipated efficient cost) of providing the service. However, in Epic, the Court found that the objective in section 8.1(a) of the Code – that reference tariffs provide the opportunity to recover efficient cost – did not take precedence over the other objectives in section 8.1 and so was not an *overarching* objective [insert ref]. It is our view that the italicised explanation was not a statement about the meaning of section 8.1(a) of the Code, but rather an explanation of the whole scheme of section 8 of the Code.

[17] This is reflected in, amongst other things, sections 8.2, 8.4, 8.9, 8.12, 8.13, 8.15, 8.20, 8.37.

[18] Sections8.3(b), (c), 8.44-8.46 (note: both the 'price path' approach and 'reference tariff control formula' approach are forms of price cap regulation).

[19] Section 8.49.

[20] This is the outworking of all of the methodologies set out in section 8.4 (indeed, if applied using consistent assumptions, the different methodologies set out in section 8.4 will provide precisely the same answer).

- with respect to asset valuation – which is a key component of the cost of providing the reference services – the Code adopts what is commonly known as the 'rolling forward' methodology, under which the regulatory value of the assets in existence at the time of the Code commencing are assigned a value,[21] and then that value is updated over time exclusively with reference to capital expenditure incurred (valued at cost) and regulatory depreciation (ie the return of funds to investors), and possibly the removal of redundant assets.[22]

In its Part IIIA Review, the Commission commented on a number of these matters, including whether regulated prices should be based upon cost; the relative merits of incentive regulation approaches (price cap regulation) as opposed to 'benchmark' (econometric) methods for setting cost-based prices; the relative merits of the building block approach and productivity-based methods for implementing price cap regulation; and the relative merits of different asset valuation methodologies. The Commission's discussion also did not distinguish between the different options as clearly as it could have – in particular, the very different role that *benchmarks* and *productivity estimates* would play in setting regulated charges. This chapter makes a number of observations about the Commission's previous consideration of these matters, as well as on the comments made in submissions to the Part IIIA Review, and seeks to provide a clear delineation of the options available.

The structure of this chapter is as follows.

- The implications of economic efficiency for the setting of regulated charges are discussed, addressing the rationale for cost to play a key role in regulated charges. We indicate support for the current principles of the Code that provide for prices to be based on costs.
- Notwithstanding this conclusion, a discussion is provided of the problems with setting prices too closely with reference to cost. Two possible approaches are described for providing regulated entities with an incentive to be productively efficient — incentive regulation (price cap regulation) and benchmark regulation,[23] and the relative merits of these approaches are assessed. We conclude that price cap regulation is preferred.
- The different means of implementing price cap regulation — the building block approach and the use of total-factor productivity — are then addressed, and their relative merits discussed. The Code provides for, and regulators have to date implemented, the building block approach to price cap regulation which we conclude to be a robust methodology and recommend that the Commission endorse this approach, at least for the current time. We also indicate the merits of a total-factor productivity approach, which could be used within the framework of regulation by price caps and price re-sets, although a robust methodology would need to be developed.

[21] Sections 8.10-8.11.

[22] Section 8.9.

[23] The term 'benchmark regulation' is used to refer to any methodology under which prices are based upon a prediction of the efficient cost of undertaking the regulated activity, where that prediction is based upon some form of econometric method.

- Finally, the merits of the asset valuation (and revaluation) methodology prescribed by the Code are discussed, in comparison with alternative approaches of re-valuation of assets at the commencement of each regulatory period. We conclude that the 'rolling-forward' methodology is one of the most important pricing principles of the Code, for both theoretical and practical reasons.

Conclusion

It is our general view that the pricing principles of the Code, while subject to some ambiguity and considerable flexibility, allow price regulation consistent with a best practice methodology. This methodology is the setting of prices with reference to cost, the use of price cap regulation, and the 'rolling-forward' approach to re-valuation of assets.

One amendment that may usefully be contemplated is to provide regulators with the flexibility to consider the use of 'total factor productivity' as an alternative approach for setting the X factor in a price cap, which may be difficult to pursue under the Code as currently drafted. However, we also consider that the building block approach remains a robust means of determining price caps, and should continue to be used until productivity based measures are demonstrated to be superior. Moreover, we would caution about overstating the gains from using productivity-based measures to set the X factor in a price cap rather than the building block approach as presently used.

An issue that we do not consider in this chapter is the actual practice of regulators, and in particular, whether they implement the best-practice regulation described below, and whether changes may be required to the Code to improve any substandard performance. On this latter point, we consider that the most appropriate means of ensuring that regulators pursue best practice is to ensure that their overall objectives are unambiguous, they operate transparently, and that effective appeals exist from their decisions. Our views on the objectives in the Code are set out in chapter 4.

3.2 Economic Efficiency and Cost Based Pricing

The Commission concluded in its Part IIIA review that the pursuit of economic efficiency is the appropriate objective for access regulation. We generally support this conclusion. The objective of economic efficiency is considered in the discussion below.

There are at least three interrelated objectives relevant to the assessment of access charges, which are:

- *Efficient pricing* – prices should signal to customers the relative scarcity of 'resources' used to provide network services. This condition ensures customers' private decisions about whether to invest in a related activity, where to invest and whether to use the system at a particular point in time are also socially optimal decisions;
- *Efficient investment* – investors must have the incentive to invest in long-lived assets that will be required to ensure that the service continues to be provided at the desired service levels over the long term; and

- *Efficient production* – the service delivered by the network is produced in the least cost manner. This requires the selection of the cost-minimising technology for providing the service given all of the available options, and the construction and ongoing operation and maintenance of the asset in a least-cost manner.

The rationale for regulation as explained in Chapter 2 is that, where firms are in a position to exercise substantial market power, they have the ability to set prices higher than required to justify the continued provision of the service over the long term, and thus create allocative and dynamic efficiency losses in upstream and downstream activities.

However, the continued provision of the service requires that the owners of the regulated activity expect to recover the economic cost associated with the provision of the service over the long term – where economic cost naturally includes a return that compensates for the opportunity cost of that investment.[24] Moreover, the fact that investors in gas transmission and distribution would expect to recover the cost associated with their investments over many years (sometimes upwards of 50 years) implies that a degree of certainty of cost recovery is important.

There is a tension between objectives of, on the one hand, minimising losses of allocative and dynamic efficiency due to a dampening of activity in upstream and downstream activities that may otherwise result from monopoly pricing, and on the other, ensuring the regulated service continues to be provided (and that new projects occur when efficient) over the long term. The logical means of reconciling these objectives is for prices to be set with reference to cost. Investors are concerned with the recovery of costs including a reasonable return — and so efficiency considerations inevitably imply that regulated charges be set with reference to cost.

Accordingly, on this matter, we agree with the conclusion that the Commission reached in its Part IIIA Review after a consideration of the issues raised in submissions:[25]

> the Commission remains unconvinced that prices can be fully decoupled from costs

The main issue for the Commission in the Part IIIA Review was not whether prices should reflect cost, but the means through which costs get translated into prices and, in particular, the incentive properties inherent in the regulatory approach.

[24] That is, provides a return as good as can be earned elsewhere, adjusted for the relative risk of different financial assets.

[25] Part IIIA Report, p.349.

This concern with the incentive properties reflects a concern about the third efficiency condition set out above, which is that the regulated services be provided at least-cost. It is now widely understood that regulatory arrangements that provide a high degree of certainty over the recovery of costs incurred — consistent with meeting the second efficiency condition discussed above — also provide less incentive for the firm to seek to minimise costs and, indeed, can provide the perverse incentive to over-spend. The US system of 'rate of return regulation' is the most obvious example of regulatory arrangements that are widely considered to provide poor incentives to minimise cost. The US institutional arrangements have generally allowed firms or the regulator to seek adjustments to prices whenever costs or revenues move such that the allowed rate of return is breached (even though, in a number of instances, prices may have remained fixed for many years).[26]

It is also widely accepted that a regulator is in a poor position to judge whether a particular project or technology or organisational structure and associated staffing levels represent efficient production. The regulated entity's knowledge of such matters outweighs vastly that of the regulator, and so attempts by a regulator to disallow perceived inefficiencies are unlikely to be effective. This is the information asymmetry problem.

- The precise nature of the information asymmetry problem needs to be understood – as it is often misinterpreted. It is reasonably straightforward for a regulator to obtain information on what a company actually has spent or done over a period, and indeed every approach to setting prices with reference to cost requires information on what companies actually have spent and done. What the regulator does not know – and may never know – is what should have been spent by the firm – that is, what would have been efficient.

The presence of information asymmetry between the regulated entity and the regulator over what is efficient practice, coupled with the poor incentive properties of regulatory arrangements that promise a high degree of certainty of cost recovery, has led to the development of alternative forms of regulation that overcome these deficiencies. The alternatives that exist — and their relative merits — are discussed below.[27]

[26] While prices may have been divorced from cost for many years, the continual *threat* of having prices reset at cost reduces the incentive to pursue efficiency gains.

[27] This section considers only the setting of the *level* of the control on average prices (that is, the level of the price cap, revenue cap or individual tariffs). Once the level of the control is determined, a second step is then to decide how to convert that average level into individual prices (and price components for multi-part tariffs) or a specific form of control (that is, under which the regulated entity has pricing discretion). Some comments on the setting of individual prices are included in footnote 34 and associated text.

3.3 Encouraging Productive Efficiency – Price Caps vs Benchmark Regulation

Price Cap Regulation

Price cap regulation is one of the manifestations of incentive regulation, the essence of which is that the regulatory regime is designed to provide firms with incentives that align its private interests with social interests — that is, to act efficiently. Given these incentives, the firm's actual behaviour should be efficient — or at least to converge towards efficiency over time. A related outcome is that observations of the firm's actual behaviour can reveal information that can be relied upon for regulatory purposes, and so improve the efficiency of the regulatory process.[28]

With respect to achieving cost efficiency, the most common method for 'aligning interests' is through the use of a price cap. Under a price cap, prices are set independently of cost for a period, which implies that the regulated entity can increase its returns by reducing its expenditure (including by meeting its service obligations using a different technology).[29] A more recent innovation in the use of price cap regulation is the introduction of a carry-over of some of the benefit from efficiency gains made in one regulatory period to the next. If properly designed, the carry-over of efficiency benefits can eliminate any reduction in the incentive to pursue efficiencies that may otherwise exist towards the end of a regulatory period.[30]

Over time, it would be expected that such incentives would lead to the firms' expenditure levels reflecting efficient levels, and reflecting new technologies and techniques as they become available. The use of such incentive arrangements have a number of benefits for all parties involved in the regulatory process.

- The presence of the incentive arrangements would permit the *regulator* to infer that a firm's actual expenditure level at the end of a regulatory period is efficient, and to use that expenditure level as a starting point when setting price caps for the next regulatory period. Accordingly, the regulator could satisfy it statutory obligations without the need to second-guess a firm's operational decisions — over which the regulated entity has substantial informational advantages relative to the regulator.
- The use of incentive arrangements should encourage efficiency gains that otherwise would not have been achieved. *Customers* would benefit as these gains are passed through into lower prices over the medium term.

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[28] Incentive regulation can be designed for many purposes. Price cap regulation can encourage productive efficiency and lead to information being revealed on the efficient cost, as discussed here. Regulated entities can be provided with flexibility over pricing and subject to a control on their pricing that encourages efficient prices to be set (although this is not always appropriate – see footnote 34). The same mechanism can be used to ensure that regulated entities have an incentive to expand the system when it is efficient to do so. An increment (decrement) can also be added to (deducted from) prices to reflect actual service levels, and provide an incentive for the optimal level of service to be selected.

[29] It was also recognised that prices could more credibly be set independent of cost for a period if prices where adjusted for inflation (thus removing a substantial risk to investors in times of inflation uncertainty) and if an offset were made for expected future productivity gains (the X factor). Accordingly, price cap regulation is also commonly referred to as CPI-X regulation.

[30] The design of such an efficiency carry-over mechanism is described in some detail in: ESC 2002, *Review of Gas Access Arrangements: Final Decision*, October.

- *Regulated entities* have the opportunity to make additional returns from above-expected performance. The regulator's use of incentive arrangements to generate outcomes like cost-efficiency would also avoid the potential need for the regulated entity to justify specific operational decisions to the regulator.

An important question to be addressed when designing the price cap regime is the strength or power of the incentive for cost reductions that is created. The answer is unavoidably a balancing of objectives. A price cap for an extended period provides a strong incentive for the firm to reduce costs, but potentially results in prices being higher than efficient costs for a long period (with a loss of pricing efficiency for the regulated market, and a loss of allocative and dynamic efficiency in related industries) and exposes the firm to a risk of cost increases (reducing the level of 'insurance' for the firm provided by the regulatory regime).

Benchmark Regulation

An alternative approach to using a price cap to overcome the asymmetric information and incentive problems is to attempt to use econometric methods to predict the efficient cost of undertaking the relevant activity – which is referred to as 'benchmark regulation' in this report. Benchmark regulation uses cost information from a large number of regulated entities, together with the information about each of the networks to adjust for factors that may cause costs to differ across networks. The outcome of such a methodology is that the regulated price is predicted, based upon information that is external to the regulated entity (at least in principle).

Numerous techniques exist for attempting to predict the efficient cost of providing regulated services; the categories identified in the recent paper to the Utility Regulators Forum were as follows:[31]

- Frontier methods – which included Data Envelopment Analysis and Stochastic Frontier Analysis;
- Econometric Benchmarking; and
- Engineering economic analysis.

The information obtained from the benchmark regulation techniques provides an estimate of the efficient cost of undertaking an activity *at a point in time*. Accordingly, where prices are to be set for a period, it would be open for the rate of change in the regulated prices to be set at a level that reflects a proxy for industry-wide productivity growth — or to re-estimate the efficient cost of undertaking the activity at more frequent intervals.

An implication of the use of external benchmark regulation is that prices would never be realigned with the actual costs incurred, but rather only ever realigned with the predicted cost of undertaking the relevant activity. Accordingly, the power or strength of the incentive to reduce cost (and level of insurance) would be high and consistent with the 'no cost insurance' model — wherein prices are not re-set to actual costs and hence there is no "insurance" for the firm that prices will be re-set to cover increases in costs, but at the same time the firm is able to retain the benefits of cost reductions in perpetuity.

[31] Farrier Swier Consulting, Comparison of Building Blocks and Index-Based Approaches, Report to the Utility Regulators Forum, June 2002, pp.32-33.

Relative Merits of Price Cap Regulation and Benchmark Regulation

The ability to use external benchmark models to set regulated charges is dependent upon a comprehensive and reliable set of information on the costs and relevant cost-related conditions of networks and a model that can predict costs to a level of accuracy that would make the methodology credible. At this stage, information for Australian firms to a sufficient level of reliability is not available at this time to permit one of the benchmark regulation approaches to be used to set regulated charges. Accordingly, the price cap method is the only viable approach for setting regulated charges in the near term.

However, a more important issue for the Commission is whether one of the benchmark regulation approaches would be a viable method even given the information required to implement it. It is our view that a benchmark regulation approach would be unlikely to be appropriate even if sufficient information existed.

Whether gas distribution and transmission business would expect to recover the cost of continuing to provide the service — or expect not to be able to finance its activities, or to earn much more than required – would depend upon the accuracy of the predicted cost, for which substantial statistical uncertainty is an inevitable feature of all of the models. The main reason is that every firm faces unique circumstances, and that such circumstances must be allowed for when deriving a prediction of what it should cost that business to provide its regulated services.

Seeking to adjust all such factors inevitably raises the risk that important explanatory variables have been omitted, or not reflected in the predicted cost because of the uniqueness of a factor to the utility in question. It needs to be borne in mind that the cost that would be incurred by an efficient operator to provide a regulated utility service today does not only depend upon today's conditions (ie topography, customer density etc), but also on history. History matters because it is always optimal to build networks incrementally, with increments sized to serve demand growth projected at a point in time. Accordingly, the historical pattern of demand growth could have a substantial effect on the characteristics of today's optimal network.

The process of 'fitting' a model to a particular regulated entity also subjects the regulator to a substantial information asymmetry problem, as the regulated entity is always going to know more about the characteristics of its system than anyone else, and regulated entities may validly complain that the level of judgement required to implement such a model exposes them to the risk of arbitrary decisions. Moreover, the information requirements for benchmark regulation models can be immense — not only requiring detailed information about the costs and specific features of the regulated entity in question, but the same information is required for a deep pool of similar entities in order to populate the relevant econometric model.

Some of the pitfalls in the assumption that benchmark techniques are preferable to price cap regulation have been summarised as follows:[32]

[32] Shuttleworth, G, 'Firm-Specific Productive Efficiency: A Response, *Electricity Journal*, April 2003, p3. This article also contains a very succinct discussion of the practice of price cap regulation, and the practical shortcomings of the use of data envelopment analysis for setting regulated charges.

> Any benchmarking technique will require pretty much the same amount of information on the company's costs — after all, one cannot carry out a benchmarking exercise without it. In addition, the exercise also requires detailed information on the factors that might be held to cause these costs ("cost drivers"). Then, one must collect all this information – on a comparable basis, with adjustment if necessary — for all the other companies used in the sample. (NSS show results for 122 companies and I presume that they collected data for them all.) Collecting such data can be a "cumbersome" exercise.
>
> Data collection is not, however, the end of the story. Any company accused of inefficiency will immediately begin to assemble evidence and explanations as to why the comparison is wrong, and why the inclusion of "company-specific factors" would lead to a different result. To show a "company-specific" effect, of course, the company must collect information on all the other companies, in order to demonstrate the difference. If the factor is highly specific to the company concerned, this exercise may be not only "cumbersome", but well nigh impossible.
>
> Hence, it is wrong (not to say logically incoherent) to say that, because COS regulation is cumbersome, benchmarking techniques must be better. In the real-life cut-and-thrust of regulatory debate, any regulatory decision will entail detailed discussion of a company's costs; benchmarking just adds a need to discuss the costs of other companies too.

In rejecting the use of benchmark regulation approaches, we endorse the comments that were made on the relative merits of benchmark regulation and price cap regulation in the Joint Industry submission to the Part IIIA review that was prepared by NECG, which included the following:[33]

> Most owners of infrastructure have little or no confidence in benchmarking approaches to efficient cost determination for use in setting regulated access prices. Vogelsang explains why this is so. He observes that regulation which makes the prices a utility can charge dependent on the performance of other firms or on some efficient benchmark "is risky for a utility to the extent that its costs differ from the yardstick by virtue of such factors as geology, climate, population density, local wage rates, taxes, or the like". Experts, particularly those with only limited exposure to the firm at issue, will often lack the detailed, firm-specific, knowledge needed to correct for these differences.
>
> In addition, there is a perception that experts may be influenced by what they perceive to be the agendas of their principals. If the principal is the owner, then experts are more likely (or are perceived as being more likely) to bend their findings to favour the owner. If the principal is the regulator, then experts are likely (or are perceived as being likely) to bend their findings against the owner.
>
> Overall, we submit that the search for efficient operational costs by analytical means is almost certain to fail in practice given the information uncertainty facing regulators. It is, in other words, ultimately likely to prove futile and socially harmful. Additionally, it is our view that that search should be unnecessary in the presence of a properly constructed regime based on incentive regulation.
>
> The theoretical basis of incentive based regulation is that efficient costs will be revealed through the operation of properly structured incentives – it is not necessary to seek to determine those costs by other means such as regulatory inquiry.

It is noted that this Joint Industry Submission was supported by almost every gas transmission and distribution company in Australia.

Accordingly, it is concluded that the Commission not recommend requiring gas distribution and transmission regulators to experiment with any form of benchmark regulation.

[33] Joint Industry Submission on the Productivity Commission's Review of the National Access Regime, Network Economics Consulting Group, June 2001, pp. 37.

3.4 Implementing Price Cap Regulation: Building Block vs TFP

Under price cap regulation, companies are provided with a commercial incentive to operate efficiently by decoupling prices from cost for a period. Certainty for investors — and protection of efficiency in upstream and downstream activities — is restored by rebasing prices in line with actual costs when prices are reviewed. In practice, this implies that the prices at the start of a regulatory period should be designed to provide a reasonable return on the regulatory value of the investments in place at that point in time, plus a return of capital (regulatory depreciation) and operating expenses incurred.

The implementation of a price cap effectively requires two decisions to be made, which are:

- to decide upon the rate of change in prices over the regulatory period – which is typically expressed as a combination of the general increase in prices (CPI) and a productivity offset (X);[34] and
- to determine the length of the regulatory period.

The issues associated with – and options open – for these two decisions are discussed in turn below.

Determining the Rate of Change in Prices – the X Factor

There are two methods that are commonly used to determine the rate of change in prices over a regulatory period (the X factor), which can be distinguished as follows:

- The first method is to forecast the rate of change in operating expenditure and the level of capital expenditure over the period, as well as the growth in demand, and then set the rate of change in prices such that the expected revenue under the price control equates with the expected cost of providing the services (both in discounted terms).[35] Under this method, assumptions about productivity growth are factored into the combination of the separate forecasts of operating and capital expenditure and demand. This approach is adopted by the UK energy and water regulators and by Australian energy regulators (and is *probably* required by the Code). This method has become known as the 'building block' approach.

[34] More precisely, the control could apply to individual prices, a basket of prices, average revenue or even revenue. Where the control is set over a basket of prices (ie the regulated entity is provided with flexibility over how it sets and changes individual prices, subject to the overall cap), the form of the control will affect the service provider's incentives over the structure of its prices and its propensity to expand the system. A recent innovation is to provide such flexibility and to design to the control to provide an incentive to set efficient charges and to expand the system when it is efficient to do so – and the tariff basket form of control is often preferred as being more consistent with this outcome. Such an approach implies that a regulator need not dictate the allocations of cost between various groups and to dictate the tariff structure. However, such pricing flexibility is not always appropriate. First, pricing flexibility is inconsistent with the use of a secondary market to expose the marginal cost of capacity at any point in time – which is the intention of contract capacity trading models for transmission systems. Secondly, where a distributor has a related party retailer, pricing flexibility may permit prices to be set in a way that impedes the entry of competitors into the retail market. Thus, the existence of vertical linkages between a distributor and a retailer may require the regulator to take an active role in cost allocation and in the structure of distribution tariffs.

[35] In practice, if the X factor is derived in this manner, then a different level for the initial prices can be selected, with a compensating effect on the X factor.

- The second method is to set the rate of change in prices with reference to a proxy for expected future total factor productivity growth for the industry (relative to the economy as a whole), for which long term historical productivity growth is generally used as the proxy. This method has a history of use in US price cap plans. This method will be referred to as the TFP approach below.

When evaluating the most appropriate method for setting the rate of change in prices over the regulatory period, it is important to focus clearly on the matter at hand, which is to determine an X factor in a price cap. We are concerned that many of the Commission's concerns about the building block approach in its Part IIIA Review are not concerns with the building block per se, but rather are concerns with forms of regulation that are not price cap regulation (but which also happen to use a cost build up model as a base).[36]

The main point of distinction between the use of the building block approach and the TFP approach for setting the X factor lies in the extent to which the X factor can be set with reference to objective evidence — and, importantly, the extent to which there is an *asymmetry of information* between the regulated entity and the regulator in the setting of the X factor. The asymmetry of information is important because regulated entities have an obvious commercial interest to do whatever they can to raise the price cap.

- Under either approach, the initial price level is set with reference to the historically incurred capital and operation costs over the previous period, and so information on actual expenditure is required. However, as all of this information is historic, an objective measure is available.
- Where the X factor is set on the basis of the long term trend in total factor productivity, then information on such matters as actual expenditure levels and on the relevant measures of output for the industry 'sample' of firms, over a reasonable period would be required. Again, as all of this information is historic, it is possible to obtain an objective measure.
- Where the X factor is set on the basis of forecasts of future expenditure requirements and demand, then forecasts of the *aggregates* of operating and capital expenditure are required. Moreover, in order to assess the trends in future expenditure requirements, a regulator may seek more disaggregated historical information (for example, to obtain an objective estimate of unit cost trends), together with other information required to assess the appropriateness of the forecasts.

[36] An example of such confusion was the Commission's reference to the requirement under the former regulatory regime for airports that required the ACCC to approve (and set a price increase for) 'all necessary new investment' (Part IIIA Report, p.343). Notwithstanding the Commission's reference to this regime as a 'CPI-X regime', the approval and setting of a price for each individual piece of investment is the anthesis of price cap regulation, and is of no relevance to the question of the relative merits of the building block approach or the TFP approach for setting the X factor.

The source of the information asymmetry between the regulator and the regulated entity when using the building block approach to set the X factor is that — by the very nature of forecasts — the variables required cannot be measured, and so will always be subject to uncertainty. Moreover, as the future expenditure requirements for a network are dependent on such factors as the current condition and utilisation of the network, as well as current business processes (and hence opportunities for future cost savings), the regulator is at a severe disadvantage to the regulated entities. In contrast, the TFP approach (at least as described above) would rely only on information that exists and hence can be measured.

This discussion would suggest that there would be merit in regulators developing the TFP approach for potential application. However, a realistic view of the benefits from the TFP approach should be retained.

- First, as discussed further below, the use of TFP to set the X factor is unlikely to provide an improvement in the incentive properties of the regime, as the incentives are created by divorcing price and cost for a period, rather than from the way the X factor is derived.
- Secondly, a substantial effort will need to be put in by regulators and regulated entities to develop the methodology for Australia, and regulated entities will have obvious incentives in the process.
- Thirdly, there is still likely to be a requirement to adjust a TFP trend to 'fit' particular entities – and so gaming opportunities will remain.
- Fourthly, a TFP-based X may not be appropriate is all situations — for example, it would not allow for discreet jumps in expenditure. Moreover, for some situations, there is little information asymmetry associated with forecasts (for example, pipelines often have very stable expenditure requirements and little room for efficiency gains — implying that it is straightforward to forecast these variables).
- Fifthly, the key strength of the TFP approach is that it relies on historical trends to set the forward-looking price path. However, historical trends can also be used to establish forecasts of operating and capital expenditure and demand required to implement the building block approach. Thus, mechanisms exist within the building block approach for reducing asymmetric information problems.

In its discussion of the building block approach in the Part IIIA Review, the Commission referred to – and at times endorsed – a number of other factors that were considered to be problems with the building block approach – which we consider to be incorrect.

First, the Commission appeared to accept that the building block approach provides inferior incentives for the regulated entity to be productively efficient than if the X factor had been based upon TFP.[37]

[37] Part IIIA Review, p.350.

Whether the X factor is set using the building block approach or by using TFP is unlikely to have an effect on the incentives of the regulated entity to be productively efficient. The incentive properties of price cap regulation derive from divorcing price and cost for a period — that is, permitting the provider to retain the additional profits (or bear the losses) associated with their performance over a defined period (that is, the regulatory period). The incremental profit that a regulated entity provider would earn from reducing expenditure at the margin — and hence its incentives to reduce costs — is independent of how the price cap was set in the first place.

The Commission also appeared to accept that the use of the building block approach would create incentives for the deferral of efficiency gains towards the end of a regulatory period, and appeared to accept the argument from a submitter to the Part IIIA review that:[38]

> efficiency carryover mechanisms designed to counteract any incentives to defer efficiency enhancements can themselves provide incentives for gaming

However, any incentive to defer efficiency gains comes from resetting prices at cost during a price review, which are an integral part of the price cap approach (the issue of the length of the regulatory period is discussed below). Hence, this potential incentive problem and will arise irrespective of whether the X was (or will be) set using the building block approach or TFP.

- The efficiency carry-over mechanism as discussed is an incentive mechanism for addressing this potential incentive problem, which works by permitting some of the efficiency benefits gained in one regulatory period to be carried-over into the next so that a continuous incentive is provided to make efficiency gains. It is far more straightforward to design an efficiency carry-over when the X factor is set using the building block approach than when TFP is used, and hence this incentive problem provides an argument for using the building block approach for setting the X.

The Commission also observed that, under a price cap regime, regulators have to 'judge whether operating and maintenance costs are based upon efficient service delivery', and 'judge whether [future capital] expenditure is justified'.[39]

In practice, neither of these are requirements of price cap regulation, even where the X factor is set using the building block approach. As discussed already above, the goal of price cap regulation is to set incentives so it can be inferred that the actual behaviour of companies is efficient — and to use the information so revealed when setting regulated charges. Thus, the use of incentives obviates the need to test the 'prudence' of actual expenditure levels. It is true that where the building block approach is used to set the X factor, the regulator has to form a view on whether the forecasts are reasonable. However, this is not a test of whether the particular expenditure item would be *efficient*, because the price cap provides an incentive for regulated entities to be productively efficient. Rather, the regulator only needs to form a view about whether the expenditure is actually going to occur, which cannot be taken for granted given the obvious incentives for the regulated businesses to overstate their future expenditure requirements (and thus raise the price cap).

[38] PC, Part IIIA, p.350. It is noted that ability for efficiency carry-over arrangements to be gamed was only asserted, and no demonstration of the scope for gaming or its materiality was provided.

[39] PC, Part IIIA Report. p.343.

Lastly, the Commission appeared to accept that the use of the building block approach is 'highly information intensive and intrusive'.[40]

This statement too may not be correct as a general proposition. The actual amount of information *required to set the X factor* using the building block approach is relatively small — not much more than the forecast of aggregate capital and operating expenditure for the next regulatory period. However, regulators would be expected to require additional information in order to assess the veracity of forecasts — but on this matter, the approaches adopted for assessing forecasts and hence the information required has differed across regulators.

In conclusion, we consider that there would be merit in regulators developing a methodology for using TFP to set the X factor in price caps. As discussed above, the primary advantage of the TFP approach is that, once the methodology is settled, asymmetric information problems may be lessened. In principle, this asymmetry of information may have two adverse effects.

- First, it is likely to imply that the regulator would set higher price caps than it had it had perfect information.
- Secondly, faced with such an asymmetry, regulators may decide to set shorter regulatory periods than they may otherwise consider optimal.

However, we consider that the building block approach for setting the X factor is a robust methodology, and should be endorsed by the Commission as an appropriate approach until the TFP approach is developed to a stage that it can be demonstrated to be superior. In particular, we do not consider that many of the criticisms of the building block approach in the Part IIIA Review were valid criticisms of this approach as a method for setting an X factor in a price cap. In particular, we do not accept the claims about its inferior incentive properties and do not consider that the concerns about 'information intensity' and 'intrusion' can be sustained as general properties.

Length of the regulatory period

The second decision for the regulator when setting a price cap is the length of the regulatory period.

As discussed above, price cap regulation works by exposing regulated entities to the profit consequences caused by differences between their actual cost incurred in providing the regulated services and the cost assumed in the price cap *for a period*, and it is inevitable that a firm's actual cost will diverge from that assumed in the price cap. A longer regulatory period implies that the regulated entity will retain the benefits – or bear the shortfall – associated with differences between its actual performance and that reflected in the price cap. Thus, the longer the regulatory period, the stronger the incentive for productive efficiency, but the greater the risk that either the entity is unable to continue to finance its activities (contrary to investment efficiency) or that profits reach an unnecessarily high level (contrary to pricing efficiency).[41]

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[40] PC, Part IIIA Report. p.343.

[41] While it is possible to exclude the regulated entity from some of the events that may affect future profitability through the use of pass-through clauses or a specific correction factor in a price cap, these mechanisms could only apply to a very narrow class of events. This is because many of the events (or the consequences thereof) that may cause cost to change are likely to be partly within the control of the

In practice, the combination of the need to secure an adequate level of investment in long-lived assets and also to ensure that customers are protected from monopoly pricing is likely to impose a constraint on the strength of the incentives for cost-efficiency that reasonably (and credibly) can be imposed. It is noted that the view that there be some brake on the strength of incentives — through a cost-based price review — is also supported by NECG, advisers to many of the infrastructure owners:[42]

> The regulator's task can therefore be viewed as one of maximising incentives for the firm to operate efficiently, while respecting the participation constraint in order to ensure continued service. Seen in this light, regulatory regimes that do secure ongoing service (i.e. the vast majority) can be compared by looking at the extent to which each offers efficiency incentives. This defines a broad spectrum of regimes, along which the balance between insurance and risk differs.
>
> At the other extreme of the "income insurance" scale, one could conceive of a regime in which a set of minimum service standards (including in terms of the prices the firm can charge) were specified, and the earnings of the firm were otherwise completely unconstrained. If the firm was able to reduce costs while conforming to the regulated standards, the resulting profits could be retained or distributed irrespective of their size. Conversely, if demand in some period(s) was unexpectedly weak, the firm would suffer the consequences even if these imposed severe losses.
>
> Such a scheme involves no earnings insurance, and offers the strongest possible efficiency incentives. Notice that this applies even though the targets will generally have been set with regard to the cost of service including the cost of necessary capital. As noted above, the participation constraint obliges the regulator to consider the cost of service. At the time it enters into the regulatory arrangement, the firm must therefore expect to at least earn its cost of capital. This does not, however, imply that the earnings of the firm are being insured, since the firm remains fully exposed to the variability of actual earnings from expected earnings.
>
> At least in theory, an extreme form of price-cap (CPI-X) regulation lies at this latter extreme of the spectrum of regulatory regimes. However, although price-caps such as these were originally thought to offer the strongest possible efficiency incentives, it is now acknowledged that practical considerations limit the extent to which this can be achieved. 5 Thus, we are not aware of any instance in which the extreme price-cap of the kind set out above has ever been successfully implemented.
>
> Thus, the end points of the continuum we have described are not feasible. There is no regime that offers full earnings insurance, and there is no regime that offers zero earnings insurance. Rather, all known regimes lies somewhere in the interior, with each reflecting its own balance between efficiency incentives and earnings insurance. Additionally, few economists would regard the extreme points as being attractive, as they take the merits one side of the continuum or the other offers to excess, completely sacrificing any element that can be obtained from the other.

However, the determination of the optimal length of the regulatory period is a complex matter, depending on both the responsiveness of a regulated entity to the strength of incentive offered, and the relative risk associated with prices either tracking too far above or below the cost of providing the regulated services.

The Code contemplates a regulatory period of generally no more than five years, although allowing for longer regulatory periods subject mechanisms to address risks in forecasting being considered.[43] The five year period reflects the standard practice of the UK energy and water regulators.

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regulated entity, and so seeking to insulate the provider from this risk would undermine the incentives for efficiency that the price cap regime was intended to generate in the first place. Extending pass throughs to a broader class of events will expand the cost of administering the price cap plan.

42 Ergas, H, J. Small, 2001, Price Caps and Rate of Return Regulation, Network Economics Consulting Group, pp.4-6 (available at: necg.com.au).

43 Section 3.18.

- It is noted even a regulatory period of five years provides a not-insignificant incentive for productive efficiency – such a period implies that if the regulated entity incurs an increase in costs by one dollar (in present value terms), then its revenue increases by only 70 cents (in present value terms).[44]

To the extent that regulators are able to set the X factor in a price cap that is less subject to the regulated entity's information advantage (ie the regulated entity having more information about the prospects of achieving lower than forecast costs), then the risk associated with extending the regulatory period beyond the current standard may be considered to fall. However, the trade-off implicit in the selection of the optimal regulatory period may differ from system to system, and a case-by-case assessment of the length of the regulatory period would be appropriate, as is currently provided for under the Code.

3.5 Regulatory Asset Valuation

As noted above, the Code requires the 'rolling forward' methodology to be adopted when establishing the regulatory value of a service provider's assets that the commencement of a regulatory period. The 'rolling forward' methodology implies taking the value that existed at the commencement of the previous regulatory period, and adding capital expenditure incurred during the last period (valued at cost) and deducting regulatory depreciation (ie the return of funds to investors).[45] An important part of the Code's methodology is that assets in place before the Code commenced are assigned a value when their first access arrangement is approved, and that value is then carried-forward and not re-opened.

- Given the significance of this initial valuation for both service providers and users – and the fact that economic principles do not provide an unambiguous answer to the valuation of such assets – regulators are provided with wide discretion when approving (and in effect assigning) the initial valuation.[46]

In its Part IIIA Review, the Commission cast doubt on the benefits associated with an alternative asset valuation (and revaluation) methodology, which is to reset the regulatory value at a new estimate of the 'depreciated optimised replacement cost' at the commencement of each new regulatory period, noting that:[47]

> in these sectors [including energy], the benefits of optimising assets seem unlikely to justify the added uncertainty and transaction cost of a DORC approach

[44] A five year regulatory period combined with an efficiency carry-over implies that any additional costs incurred are borne by the regulated entity for the first five years, which accounts for approximately 30 per cent of a perpetuity (using a real discount rate of 7 per cent).

[45] If a real return had been provided on the asset base during the previous regulatory period, then an adjustment for inflation over the period would also be undertaken. The Code also permits (but does not require) a regulator to contemplate removing redundant assets – subject to safeguards (sections 8.27-8.29). We advise regulators against retaining the discretion to identify and remove assets considered to have become redundant or partially redundant.

[46] Sections 8.10-8.11. As the Epic case has demonstrated, the assigning of this initial valuation can be (and has been) controversial. However, under the Code, once the initial value has been set it is then fixed for future reviews.

[47] Part IIIA Review, p.366.

We consider that the Commission's scepticism about the merits of continually resetting regulatory asset values at an estimate of their depreciated optimised replacement cost values is well placed. We consider the approach to regulatory asset valuation in the Code to be one of the most important of the Code's pricing principles for reasons as follows.[48]

First, price cap regulation – as described above – requires the 'rolling forward' methodology to be applied to re-establish the regulatory asset base at the time of a price review. The purpose of a price review is to reset prices in line with cost, and so place a limit on the extent to which prices can diverge from cost (and thus limit the risk that either the business cannot finance its operations or that prices unnecessarily depress activity in related markets), which can only be achieved using the rolling forward method. Similarly, the 're-DORC' method is subject to the same criticisms as the other benchmark regulation approaches discussed above.

- That is, there is an alternative to benchmark regulation to provide regulated entities with an incentive to be productively efficient, that is more capable of being implemented and that provides a more appropriate balance between the incentive for productive efficiency and the risk associated with prices diverging too far from cost over the long term (the alternative being price cap regulation).

Secondly, any methodology for resetting the regulatory value at an estimate of DORC implies high administrative costs, exposes the regulator to asymmetric information problems and invites substantial unnecessary argument. Moreover, a large number of difficult implementation issues would need to be resolved in order to contemplate resetting regulatory values to their DORC value at each review.[49] To date, the attention to – and public debate upon – the application of the DORC methodology has been limited.

Thirdly, and importantly for the gas industry, the resetting of the regulatory value at DORC at successive price reviews takes away any flexibility over regulatory depreciation,[50] and which may imply a recovery of capital that is highly inefficient and inappropriate for new pipelines. In particular, the resetting of the regulatory asset value at the DORC value at each price review may (depending on the length of the regulatory period) preclude the recovery of capital to be deferred from the early years of an asset's life years when use of the pipeline is low to later years when the use would be projected to be much higher.

[48] The Allen Consulting Group recently was commissioned by the Australian Competition and Consumer Commission advising on the appropriate methodology for updating the regulatory values of electricity transmission assets, and recommended that the Gas Code approach be extended to electricity transmission: The Allen Consulting Group 2003, *Methodology for updating the regulatory value of electricity transmission assets*, report to the Australian Competition and Consumer Commission, August (available at: www.accc.gov.au). That report contains a detailed discussion of the advantages and disadvantages of the different asset valuation approaches.

[49] See The Allen Consulting Group 2003, *Methodology for updating the regulatory value of electricity transmission assets*, report to the Australian Competition and Consumer Commission, August (available at: www.accc.gov.au), chapter 3.

[50] This is because if regulatory values are reset exogenously at periodic intervals, the regulatory depreciation that is factored into prices in between the two points in time needs to be an unbiased forecast of the change in the regulatory value over this period (adjusted for projected additions).

The UK Office of Telecommunications Regulation, in explaining its approach to modelling economic depreciation for regulated mobile termination calls, reached a similar conclusion:[51]

> 20 One way to specify the competitor constraint would be the contestable market approach. It could be assumed for the purposes of the analysis (even if this represents a departure from reality) that entrants never experience a type (i) difference compared to incumbents. In a contestable market entrants face no barriers to entry and so would always be able to achieve the same utilisation as the incumbent(s) in any calendar year. So, for illustration, assume that the incumbent invested three years ago and achieved 50% utilisation in its first year of operation and 75% in its second year before reaching 100% in the current year. The contestable market approach would mean that the entrant in the current year would be assumed to achieve 100% in the current year, its first year of operation (and so has greater type (ii) efficiency than the incumbent).
>
> 21 Competition from potential entrants to a contestable market would be sufficient to ensure the removal of super-normal profit (whatever the number of incumbents or the nature of competition among them). The incumbent would be unable to defer depreciation when utilisation is low. If input costs (MEA price and operating expenses) were constant, then the economic depreciation profile under contestability would be a constant annual cost recovery (in £) each year. The unit cost (or price) would be inversely proportional to utilisation.
>
> 22 Although contestability provides a feasible answer to the specification of the competitor constraint, the price/unit cost profile that it implies seems unattractive. When utilisation is very low, the price/unit cost is very high and vice versa. It also involves an assumption about new entrants that seems very unrealistic.

Fourthly, and related to the last point, the resetting of the regulatory value at DORC at successive price reviews implies that any overstatement or understatement of regulatory depreciation will provide a windfall gain or loss respectively, thus increasing the extent of dispute about depreciation. In contrast, where the roll-forward method is used to update regulatory values, regulatory depreciation affects only the time profile of revenue but not the value of that cash flow (using the regulator's estimate of the cost of capital).

Indeed, given the neutrality of regulatory depreciation, some regulators have noted the benefits of providing regulated entities with flexibility over regulatory depreciation. For example, the Victorian Essential Services Commission noted the following in one of its consultation papers in its most recent review:[52]

> In *Consultation Paper No. 1*, the Office indicated that it considered there to be substantial benefits to both customers and distributors from a policy of minimising the risk to distributors associated with recovering the regulatory value of their assets. Consistent with this approach, the Office expressed the view that:
>
> - with respect to *regulatory depreciation* (return of capital), distributors should have a degree of flexibility over the rate at which capital is returned, and in particular to take account of technological change, projected future demand and any other factors that may affect the (unregulated) market value of their assets in the future; and
> - with respect to *redundant capital*, the Office would choose not to preserve the flexibility to write-down the regulatory value of distributors' assets at a future regulatory review.

Accordingly, we recommend that the Commission endorse the principles in the Code governing the revaluation of assets over time as the most appropriate methodology.

[51] Oftel, Calls to Mobiles: Economic Depreciation, undated (available at: http://www.oftel.gov.uk/publications/mobile/depr0901.htm)

[52] Office of the Regulator-General, 2003 Review of Gas Access Arrangements: Position Paper, September 2001, p.36.

Chapter 4

Objectives of the Code

4.1 Introduction

In its Part IIIA review the Commission highlighted the importance of objectives in any regulatory framework:

> "Clear specification of objectives is fundamental to all regulation. It is particularly important where there is scope for divergence between the intent of regulation and the interpretation of its operational criteria. More specifically, for access regimes to function efficiently, clear objectives are needed to promote:
>
> - decisions that are well targeted to the identified problem and which minimise unintended side effects;
> - greater certainty for current and prospective facility owners, access seekers and other interested parties;
> - consistency among policymakers, the judiciary and those responsible for implementation and enforcement; and
> - regulatory accountability.

In is our view that the current objectives and principles in the Code are ambiguous in the guidance they provide to regulators, including in respect of the tariff principles of section 8 of the Code. While we consider that the Code can be administered, the multiplicity of objectives and principles in the Code, and their inter-play, means that regulators have to reconcile competing interests and take into account a range of factors without clear guidance on the relative weightings to be afforded to each. The inevitable implication is regulators' decisions would be expected to be less transparent and the actual decision making process more complex. Clarification of the Code's objectives would result in a more effective access regime for Australia's gas industry.

The current guidance provided to regulators is discussed below first, and then our views on the appropriate objective for the Code.

4.2 Current Guidance Provided by the Code

An example of the ambiguity in the scheme of the Code exists in the requirements of the Code in respect of determination of reference tariffs.

Section 2.24 of the Code provides that a regulator may only approve a proposed access arrangement if the regulator is satisfied that the proposed access arrangement contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code. Further, section 2.24 requires that the regulator must also take into account the wide-ranging list of factors contained in section 2.24:

> (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 operation 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.

Sections 3.3 to 3.5 of the Code require that an access arrangement include a reference tariff and reference tariff policy that complies with principles set out in section 8. In turn, section 8.1 of the Code requires that a reference tariff and reference tariff policy be designed with a view to achieving the following objectives:

(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

While section 8.1 provides that a regulator may determine the manner in which conflicting objectives of section 8.1 may be reconciled, section 8 provides no guidance to the regulator in the exercise of this discretion.

The construction of the Code in respect of the determination of reference tariffs was addressed in a judgment by the Supreme Court of Western Australia in a judicial review of the draft decision of the Western Australian Independent Gas Pipelines Regulator on the proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline – 'the Epic decision'.[53] The Court's determination in this respect was that in deciding how to weight and reconcile the section 8.1 objectives, the regulator must have regard to the factors in section 2.24, as cited above.

[53] Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231

There has been much written about the Epic decision and its implications for future regulatory decisions. A key point of agreement in these commentaries is that the decision has broadened the discretion of regulators under the Code to take into account and give greater weight to factors other than economic efficiency in establishing regulated tariffs, with particular reference to the factors of section 2.24. However, the factors of section 2.24 do not constitute objectives or principles and thus do not provide guidance to the regulator in the form of over-riding objectives or principles. Rather, they just inform the regulator that there are competing interests to be considered. Thus, the judgement has not resolved the issues of multiple objectives and their inter-play and may have actually made regulatory decision making a more complex, uncertain task.

There are a several other major implications of the Epic decision for the operation of the Code's objectives and principles.

The Epic decision indicates that the regulators assessment of a proposed access arrangement should be a 'single process' taking into account the factors of section 2.24 of the Code.[54] However, it is difficult to establish unambiguously what this means. For example, it may mean that a regulator has to consider in an overall sense whether an access arrangement is acceptable or not, rather than looking at each individual component of an access arrangement. In this case, a regulator has a general role (and a general discretion) to make a decision to accept or reject an access arrangement in total. It is possible that a regulator may thus accept an access arrangement because, on balance, it meets objectives implicit in the factors of section 2.24 even though it may not strictly comply with requirements of sections 3.1 to 3.20 of the Code. The implication of this interpretation is an increase in the discretion of regulators.

The Epic decision diminished the importance of considerations of economic efficiency in the setting of regulated prices. The Court did not give attention to the preamble to section 8 of the code and the guidance in that preamble that the overarching consideration in the setting of tariffs is that tariffs reflect efficient costs.[55] The Court also gave little attention to the preamble of the GPAA as an element of guidance to the Regulator – which, but rather referred to the implicit objectives in the preamble only in discussion of partial similarities with elements of the Code.[56] The Court established a hierarchy of principles in the Code by indicating that a reference tariff must satisfy the principles of section 8.1 and that the regulator must take into account the factors of section 2.24 where necessary to resolve any conflict between the principles of section 8.1. As already mentioned above, the factors of section 2.24 simply set out a number of factors to be considered by regulators in assessment of a proposed access arrangement, with establishing principles or objectives to guide regulators in this consideration. It is notable that there are significant differences between the objects of the GPAA as set out in the preamble and the factors of section 2.24, most notably that the objective of preventing abuse of monopoly power does not appear as one of the factors set out in section 2.24.

[54] Ibid, para 61.
[55] Ibid. para 160.
[56] Ibid. para 133.

While the Court's deliberations occurred in respect those parts of the Code relating to the determination of reference tariffs, the obvious extension of the Court's determination is that where sections 3.1 to 3.20 of the Code establish particular objectives or principles for an element of an access arrangement, that it is these objectives or principles that in the first instance guide a regulator's assessment of the relevant element of the access arrangement. The factors of section 2.24 are referred to the regulator where necessary to resolve conflict between conflicting objectives or principles.[57] However, there is an obvious conflict between this finding of the Court and the finding that the assessment of a proposed access arrangement should be a 'single process' taking into account the factors of section 2.24 of the Code, as described above.

4.3 Discussion

The removal of the current ambiguity in operation of the Code's objectives and principles would improve both the workability of the Code and the certainty of decisions made there under. The Epic decision has increased rather than removed this need.

We submit that the Code should include a single overall objective that can be used to reconcile the conflicting guidance of the subsidiary provisions. The incorporation of an overall objective would remove the ambiguity in the operation of the Code's current objectives and principles.

The specified 'objectives' in other regulatory frameworks incorporate a wide-range of issues and elements. There are objects clauses that make specific reference to the importance of the consumer. For example in the Australian telecommunications industry, the object is:

> (1) The object of this Part is to promote the long-term interests of end-users of carriage services or of services provided by means of carriage services.

Similarly, the objects clause relevant to the gas industry in the UK directs primary consideration to the impacts of decisions on consumers and includes reference to promoting effective competition:

> (1) The principal objective of the Secretary of State and the Gas and Electricity Markets Authority (in this Act referred to as "the Authority") in carrying out their respective functions under this Part is to protect the interests of consumers in relation to gas conveyed through pipes, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas so conveyed.

The Commonwealth Government proposed that an appropriate objects clause for access regimes includes economic efficiency with references to competition and investment. In responding to the Commissions Part IIIA review, the Commonwealth Government proposed the following objects clause:

> The object of this Part is to:
>
> (a) promote the economically efficient operation and use of, and investment in, essential infrastructure services, thereby promoting effective competition in upstream and downstream markets; and

[57] We note that in many areas, particularly in the application of some of the pricing principles, the Code does not provide for the exercise of discretion by regulators. Thus, the problem of multiple and conflicting objectives does not impact on all aspects of decision-making under the Code.

(b) provide a framework and guiding principles to encourage a consistent approach to access regulation in each industry.

These other access regimes have economic efficiency as a primary objective. The adoption of an objects clause in the Gas Pipelines Access Law or Code that is focused on economic efficiency would be consistent with supporting well-targeted decisions, increased certainty, consistency and accountability. Economic efficiency is not inconsistent with the elements of consumer protection, investment or competition, which have been incorporated into objects clauses in various regulatory regimes, including those outlined above.

However, it is not obvious that the inclusion of elements in addition to economic efficiency, or qualifiers to economic efficiency, necessarily adds to the intended objective of economic efficiency. In contrast, the inclusion of such qualifiers may inadvertently result in an possibly very important dimension of efficiency from being able to be considered, as well as be contrary to encouraging a consistent approach to access regulation.

The adoption of an objects clause focused on economic efficiency is consistent with supporting well-targeted decisions, increased certainty, consistency and accountability. Thus, the incorporation into the Law or Code of an overall objective with a primary focus on economic efficiency meets would meet the criteria established by the Commission for objectives clauses in its Part IIIA review.

Regarding the implementation of this objective, amendment of the Law and/or Code to make reference to the objects of the enabling Acts of each jurisdiction – which are the objects of the Natural Gas Pipelines Access Agreement[58] – may not, in itself, be sufficient to provide clarity of objectives of the Law and Code without further definition of these objectives, and in particular clarifying the economic meaning of the objectives. The Epic decision has highlighted this need in respect of the objective of preventing abuse of monopoly power, as evident from a commentary on the decision:[59]

> [T]he Court found that there was not a sufficiently established or settled meaning in the field of economics of the concept of an abuse of monopoly power. Both the Act and the Code have as their objectives the prevention of the abuse of monopoly power. … What guidance does the judgment give service providers and the regulator as to the prevention of the abuse of monopoly … .
>
> It is submitted that the answer to that question is "very little". The judgment is difficult to follow and fails to provide any satisfactory indication of what might constitute an "abuse of monopoly power".
>
> In particular at paragraph 121 the Court stated that the evidence had not shown that the word abuse referred to pricing by a monopolist which either exceeded prices that would be achieved in a competitive market or exceeded prices set to reflect theories of economic efficiency. However the Court took the matter no further. Accordingly based on paragraph 121 one is left to ask what does constitute an abuse of market power if monopoly pricing does not?

[58] Natural Gas Pipelines Access Agreement, sub-clause 2.1.

[59] Carson, J., 2002. The Epic Energy Decision. Australian Mining and Petroleum Law Associaation Limited, Annual State Conference (WA Branch) Rottnest Lodge, 18 October 2002.

Chapter 5

Empirical Evidence on the Stance of Regulators

5.1 Introduction

Over recent years, a consistent criticism made of regulators is that they have set prices for regulated services that are too low, and that threaten the incentives on regulated firms to undertake the investment required to provide the levels of service sought by customers. Gas industry regulators have not been immune from this claim.

The potential for regulators to be too harsh was also reflected in the comments of the Productivity Commission in its review of the National Access Regime:

> … when intervention occurs, it is important that regulators are not overly ambitious in their attempts to remove monopoly rent. ... (this) means that access regulation must recognise the potential costs of a 'surgical' approach to rent removal and encourage regulators to focus on the more modest objective of reducing demonstrably large rents resulting from inefficient pricing or denial of access.
>
> Productivity Commission 2001, Review of the National Access Regime, Report No.17, AusInfo, Canberra, p.94

Criticisms are most commonly levelled at regulators' estimates of the cost of capital associated with a regulated activity. For example, in the context of a recent price review, AGL commented that:

> …AGL notes the disturbing trend of decreasing rates of return in recent regulatory decisions in relation to energy infrastructure. … AGL believes that this trend is the result of an increasingly detailed focus on the individual components of the Capital Asset Pricing Model and WACC formulae without adequate attention to the reasonableness of the results.
>
> KPMG and AGL report to accompany AGL's submission to IPART DP 56, October 2002

The same criticism has also been levelled more recently at regulators in the wider media, for example:

> Regulators must estimate … the business's WACC.
>
> The problem is that accurate information on several of these parameters does not exist. But this has not deterred regulators. For example, even though market information does not exist to quantify some of the key parameters of the WACC, regulators have been consistently prepared to move to the bottom of a range of acceptable values, to assume that the enterprises' capital will be comparatively cheap. Pity the company whose capital is expensive. To make matters worse, regulation is applied as a one-way bet: bad luck if the regulated business cannot recover its costs, but rest assured that it will never earn more than a 'normal' return on its investment.
>
> Ergas, H, 'Off With Their Heads – When Regulators are Making Determinations Based Upon Their Own Assumptions – Not Facts – it is Time for a Change', Business Review Weekly, 14 August 2003, p.54.

However, to date, the question of whether regulators have erred in their treatment of regulated utilities has relied heavily on statements – often by parties with a direct commercial interest in the outcome – either unsupported by evidence, or supported by evidence that is only anecdotal in nature.[60] The Victorian Essential Services Commission has previously expressed its views on some of the 'evidence' presented during a recent price review that sought to demonstrate that it had understated the cost of capital associated with the distributors' regulated activities:[61]

> Notwithstanding the distributors' numerous comments that the Commission should have regard to 'market practice', the distributors or submitters on their behalf have provided very little in the way of credible information that would assist the Commission to obtain an unbiased view of the discount rates employed by market practitioners. The Commission is particularly concerned that the distributors or submitters on their behalf continue to refer to or produce opinions from parties that are produced for the sole purpose of a regulatory proceeding, are not accompanied with any evidence that those opinions are consistent with assumptions adopted in normal practice, and are provided by parties with a direct financial interest in the outcome.
>
> …
>
> Regarding the opinions of the two investment banks presented by [the distributor], those opinions were expressed for the sole purposes of a submission to the Commission, were not supported by any analysis and did not include evidence that the opinions expressed were consistent with the assumptions they had adopted for purposes unrelated to a regulatory proceeding. In addition, both of these investment banks had had recent commercial relationships (or, in the case of one, an ongoing relationship) with [the distributor]. Similarly, the opinions of the institutional investors who expressed opinions on the returns required by investors in 1998 were also expressed for the sole purpose of the regulatory proceeding, none provided any evidence that the opinions expressed were consistent with the assumptions actually adopted in their 'market practice' and all had significant interests in regulated utilities at the time of making its comments.
>
> In light of these matters, the Commission considers that it should place commensurately less weight on the opinions referred to …

The purpose of this chapter is to present and assess a source of a verifiable empirical evidence of whether Australian regulators have set 'overly ambitious' price constraints for regulated entities, which is the relationship between the market value of a regulated activity, and its regulatory value. As will be discussed below, the two values have a necessary mathematical relationship, and a comparison between the two can shed light on the accuracy of the totality of a regulator's decisions when setting reference tariffs.

5.2 Expected Relationship between Market Values and Regulatory Values

An understanding of the relationship between the market value of an asset and its regulatory value requires an understanding of the definition of the regulatory value of an asset, and its role in setting regulated charges (such as reference tariffs).

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60 The cost of capital associated with a project is the price of attracting and retaining investment funds in an activity, and depends upon the aggregate demand and supply of investment funds, as well as the relative risk of the project in question. However, unlike the prices of other goods or services, the price of investment funds cannot be observed, but can only be estimated from the available capital market evidence. Thus, neither the regulated entity nor the regulator can know the cost of capital associated with an activity – both can only estimate it.

61 Essential Services Commission, Final Decision: Review of Gas Access Arrangements, October 2002, pp.371-372.

As discussed in chapter 3, one of the implications of economic efficiency is that regulated charges should be set such that the revenue received is expected to permit the recovery of the costs incurred in providing the regulated services, including a reasonable (risk-adjusted) return on capital invested,[62] although revenue and cost would be permitted to vary for a period to provide an incentive for productive efficiency. An alternative statement of this proposition is that the regulated charges should be determined such that the value of the expected cash flow generated from those charges is equal to the costs incurred.

In practice, many of the inputs required to provide infrastructure services are expected to continue to deliver the service over many years, and the recovery of the costs associated with such assets is typically spread over many years. Accordingly, at any point in time, a regulated entity is likely to have recovered some of the costs that were incurred in providing the regulated service, but to have a residual unrecovered portion that should needs to be reflected into future regulated charges – much like the principal remaining on a home loan. The remaining residual value (or unrecovered cost) at any point in time is the regulatory asset value.

An important issue for the objective of encouraging new investment is how the regulatory asset value changes to accommodate new investment. Under the 'rolling-forward' approach that was discussed in section 3.5, the regulatory value of the asset is adjusted from one period to the next by adding in new investment at cost, and deducting the amount of the invested capital that has already been returned to investors (regulatory depreciation, which is the equivalent of the repayment of principal on a home loan). The effect is that if $1 is invested in the network, the regulator would seek to set prices such that the market value of the entity also increased by $1 – which would imply that investors were compensated for the costs incurred (including a reasonable risk-adjusted return) and investment would proceed.

A necessary implication of the discussion above is that the objective of a regulator when setting regulated charges is to determine charges such that the value of the expected future cash flows is equal to the regulatory asset value at that point in time.

The standard approach that regulators use to assess the value of the cash flow associated with a given set of regulated charges is to determine the present value of those cash flows.[63] More precisely, the task of a regulator can then be defined as finding a control on prices such that:[64]

$$RAV_0 = \frac{\vec{P}_1^{reg}.\vec{Q}_1^{reg} - C_1^{reg}}{(1+R)} + \frac{\vec{P}_2^{reg}.\vec{Q}_2^{reg} - C_2^{reg}}{(1+R)^2} + \cdots + \frac{\vec{P}_n^{reg}.\vec{Q}_n^{reg} - C_n^{reg} + RAV_n}{(1+R)^n} \qquad (1)$$

[62] Or, more particularly, the return should reflect the opportunity cost associated with investing in the activity, which is the return foregone by not investing in alternative activities (adjusted for the relative risk of the investments).

[63] While regulated prices are commonly determined by applying a rate of return to a regulatory asset value adding on operating expenses and regulatory depreciation, such a calculation is derived from – and is equivalent to – the present value calculation set out in equation 1. A demonstration of the derivation of the common 'return on regulatory asset base' formulae from a present value calculation can be found in: The Allen Consulting Group, Working Capital: Relevance for the Assessment of Reference Tariffs, Report to the ACCC, March 2002 (available from the ACCC's website: www.accc.gov.au).

[64] The vector notation reflects the fact that the regulated entity may have a number of tariff classes, each with a number of price components.

where:

- P_i^{reg} is the regulator's forecast of the price for each service and charging component that would result under the price control for year *i*,
- Q_i^{reg} is the regulator's forecast of future demand consistent with each service or price component in year *i*,
- C_i^{reg} is the regulator's forecast of future expenditure requirements (costs) for year *i*;
- *R* is the regulator's estimate of the cost of capital associated with the regulated activity; and
- RAV_0 is the regulatory asset value at the start of the regulatory period (end of year 0) and RAV_n is the regulatory asset value at the end of the regulatory period (end of year *n*) – and, implicitly, the regulatory period lasts for *n* years.

In undertaking such a calculation, it is important to ensure consistency between the version of the cost of capital that is used and the definition of the cash flow. Amongst other things, this implies that:

- if cash flow to investors is defined as the return to all providers of finance (ie equity and debt), then the discount rate should be a weighted average cost of capital;
- if cash flow is specified in nominal terms, then a cost of capital defined in nominal terms is required, and alternatively, if the cash flow is defined in constant price (real) terms, a cost of capital defines in real terms is required; and
- if cash flow is defined in after tax terms, then the version of the cost of capital needs to be defined in after tax terms.

These matters are understood by regulators and taken into account.

It necessarily follows that if the regulators were to achieve the objective of setting a price that was expected to permit all costs to be recovered – including a reasonable (risk-adjusted) return that is equal to the actual cost of capital for the asset – then the actual market value of the asset in question and the regulatory value would coincide precisely with the regulator's target for the market value (ie the regulatory asset value), at least at the time of a regulatory review. Thus, to the extent that the market value of the asset exceeded the regulatory value, then the regulated charges would overcompensate for the cost of providing the regulated service.

- As the net effect of all of the regulator's assumptions can be expressed in terms of the resulting return on investment, an observed market value in excess of the regulatory value would imply a return in excess of the reasonable (risk-adjusted) return for undertaking that activity.
- Equally, to the extent that the market value of the regulated asset fell below its regulatory value, then it could be concluded that the regulated charges determined by the regulator provided a return below the cost of capital associated with that activity.

If investors value assets using the same approach as regulators – that is, using discounted cash flow analysis – then the possible sources for the difference between the market and regulatory value would be expected to reflect the net effects of:

- the regulator adopting a more conservative assumption about the prices that a regulated entity may be able to charge under the price control than investors;[65]
- the regulator adopting a more conservative assumption than investors about the quantities of the regulated service that would be sold during the next regulatory period;[66];
- the regulator adopting a more conservative assumption than investors about the expenditure requirements over the next regulatory period (which may reflect the regulated entity achieving greater productivity gains than that assumed by the regulator);
- investors adopting a view that the risk-adjusted return required to invest in the regulated activity (ie the cost of capital) is lower than that adopted by the regulator; and/or
- the regulated entity expecting the regulator to continue to make similar errors into the future.

Importantly, however, a comparison of the market and regulatory values does not require investors to use the same valuation methodology as the regulator, so that if, for example, the capital asset pricing model (a common model for estimating the cost of capital associated with an activity) was considered inappropriate, then the market value of the asset would reflect a different expected return. In addition, it would be expected that the market value of the asset reflected all relevant future events. Thus, if investors considered that returns may be truncated (for example, unlimited on the downside but limited on the upside), then this view would be reflected in their cash flow forecasts (and a lower market value than otherwise).

Another factor that would cause a difference between the market value and regulatory value of a particular entity is where the entity undertakes other activities in addition its regulated activities. The most common example for this in the energy area would be a distributor also undertaking retail activities. However, this source of difference between the values – which is a spurious source of difference – can be eliminated by careful interpretation of the empirical information.

[65] This source of value is likely to exist where the control on prices set by the regulator places a cap on the weighted average price rather than each individual price. Under such an arrangement, the rebalancing of charges can deliver an increase in revenue.

[66] The ability to sell an interruptible service – which a regulator may not have taken into account when setting regulated charges – is one example.

Other References to the MV/RV Relationship

The role and definition of the regulatory value assigned to the assets required to provide a regulated service discussed above is well understood by regulators and commentators. By way of example, the then Victorian Office of the Regulator-General described the role of the regulatory asset base in identical terms when it assessed the first access arrangement for the three Victorian distributors in 1998.[67]

> **Capital Base** - this is the value that the regulatory regime ascribes to the assets that are used to deliver the Services. At any point in time, the Capital Base can be interpreted as the net present value of income that the regulatory regime will provide to those assets over their remaining economic life. This has the following implications:
>
> – the initial Capital Base can be defined as the net present value of income that the regulatory regime will provide to the assets that are in existence when the first Access Arrangement for that Pipeline is approved; and
>
> – as new assets are valued at their actual cost, the Total Revenue will be designed to provide a new investment project with a net present value of income over its economic life equal to zero.

Importantly, this statement was made – and the starting value of the relevant assets was set – prior to the three Victorian gas distributors being privatised.

Academics had also reached the same (almost trivial) conclusion on the role of the regulatory asset base many years earlier. For example, Greenwald noted the following:[68]

> the rate of return on a utility's assets will be equal to that available on commensurately risky assets, if and only if, the market value of the utility is equal to its rate base.

In addition, the obvious relationship between the market value of an entity and the regulatory value of its assets that was discussed above has also been recognised by regulators in Australia, commentators in the UK and other commentators in Australia. When discussing the relevance of 'other information' on the cost of capital associated with the Victorian distributors' regulated activities in its recent access arrangement review, the Victorian Essential Services Commission commented as follows:[69]

> … the setting of regulated charges involves, in effect, finding a price that would provide future cash flows with a market value equal to the regulatory value at the start of the regulatory period, given the regulator's assumptions about the cost of capital, future expenditure requirements, demand and other factors. It necessarily follows that if all of the regulator's assumptions were unbiased forecasts, the market and regulatory values of the relevant asset would coincide exactly. Equally, the market value would only exceed the regulatory value if the net effect of all of the errors in the regulator's forecasts favoured the regulated entities.

The ESC also noted that the three distributors also acknowledged implicitly this argument in their submissions to the review referred to above.[70]

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67 Office of the Regulator-General, 1998, Access Arrangements for Multinet, Westar and Stratus: Final Decision, October, p.49.

68 Greenwald, B., 1980, 'Admissible Rate Bases, Fair Rates of Return and the Structure of Regulation', *Journal of Finance*, Vol. XXXV, No.2, p.362.

69 Essential Services Commission (Victoria), 2003 Gas Access Arrangement Review: Final Decision, October, p.372.

70 Essential Services Commission (Victoria), 2003 Gas Access Arrangement Review: Final Decision, October, p.372.

The relationship between the market and regulatory values of assets has been of particular interest in the UK, as recent price reviews there have lead to the market value for a number of companies falling below their regulatory values. In a submission to Ofgem, Dr Keith Palmer, Vice President of Investment Banking at NM Rothschild and Sons, commented as follows:

> The equity market valuation of regulated assets is significantly lower than the regulatory asset value and has remained at discount since the last price review. This discount has persisted despite industry performance broadly in line with the regulator's ex ante expectations. This is evidence that the expected return from holding regulated water assets is lower than the cost of equity to the sector. If this remains the case then the water industry will not be able to raise new equity in the future …[71]

Moreover, the expected relationship between the two values was also set out in some detail as early as 1996 – and indeed, proposed as a relationship that could be used to provide a market-based check on the decisions of regulators.

> In the economic literature, Tobin's Q is the ratio of the market value of a firm to the replacement cost of its assets. It is a theory about what drives investment. In a competitive world, when the market value gets above the replacement cost, it is a signal to invest in physical assets rather than take over other firms. In the regulatory context, Tobin's Q is the ratio between the market value of the utility and its regulatory rate base. …
>
> …
>
> The fundamental idea behind regulatory Tobin's Q is this: if the regulator is doing his or her job properly, the stock market valuation of the utilities should be broadly in line with the regulatory rate base. (Perfect knowledge and foresight would be needed to have regulatory Tobin's Q exactly equal to 1.) The main advantage in going for Tobin's Q as a regulatory tool is that it ties down the regulator. For it to work, there has to be a commitment by the regulator to the rate base. Q cannot be determined without a clear rate base. It also involves a commitment to an expected Q of 1: the balance should balance.
>
> - Q=1 implies that the market expects a normal return on the rate base.
> - Expected Q=1 refers to the expected value at the end of the review period, which is more relevant if the regulator intends to phase out extra profits over a review period, in order to provide a longer term incentive for efficiency gains.
>
> From the utilities' point of view, the regulatory golden rule becomes: Q>1 means heaven and Q<1 means hell.
>
> Graham Houston, 1996, Regulatory Tobin's Q, Tracking Shares and all that, NERA Topics No. 18, pp.2-3 (available at www.nera.com).

The author of the paper referred to above recommended to regulated companies to issue special classes of shares as a low cost means of providing the market information. It is important to note that the lessons from the UK are equally applicable here. That is, the inputs that are required by regulators – the cost of capital and forecasts of expenditure – and the methodology for converting financial inputs into a price cap, are the same. Accordingly, the same expected relationship between the market and regulatory values for assets – and the same implications of a difference in the values – exist between the two countries.

Moreover, Australian academics have also noted the relationship. Professor Davis from the University of Melbourne commented as follows:

> If a competitive risk-related rate of return applied to the regulatory asset base is used in access pricing determinations, the market value of the assets should equal the regulatory asset base.
>
> Davis, K, 2002, 'Asset Pricing and Asset Valuation', *Agenda*, Volume 9, No. 3, pp. 223-235

[71] Quoted in: Envestra, TXU and Multinet, Joint Submission: Response to the Customer Energy Coalition comments on the Cost of Capital, 6 September 2002, p.8

Lastly, the existence of the relationship between market and regulatory values has also been acknowledged by other commentators in Australia, and indeed, in a previous submission to the Commission. In particular, NECG commented as follows:

> Further evidence to suggest that Ofwat misjudged the industry's cost of capital can be seen in the relationship between companies' market capitalisation and the value of their RABs. If Ofwat has correctly assessed the cost of capital, one might expect the two to be roughly equal.
>
> NECG, International comparisons of rates of return, comment on NERA paper, p.7. 18 July 2001

Accordingly, the expected relationship between the market and regulatory values of assets is considered a robust relationship, and accepted by other commentators.

5.3 Empirical Evidence

Over the period since 1994, there have been a large number of privatisations of energy utilities in Australia, a number of subsequent sales of those privatised assets, and also a number of listings of privatised energy assets. The prices at which these assets have been sold and re-sold, and the implied market value of assets derived from share prices (for the listed firms), provide a wealth of evidence from which to examine the relationship between the market and regulatory asset values.

The Allen Consulting Group has undertaken a detailed analysis of the relationship between the market and regulatory values implies by transactions or share prices for Australian energy utilities, the results of which are set out in this section. Appendix A to this report provides further details on the transactions that have been examined, and the methodology that has been adopted.

A caveat that needs to be borne in mind when interpreting these results is that the sample of enterprises in this report include only businesses that serve mature energy markets, and are likely to possess substantial market power. Thus, the results do not necessarily extend across other projects — such as greenfields projects. However, as noted in chapter 2, much of the role of the Code is the regulation of such mature systems.

Methodology

Sample of Entities

As noted above, the analysis presented in this chapter has examined transactions for *energy utilities* – that is, electricity and gas – rather than just gas utilities in order to provide a larger sample of transactions than would occur if the sample size were just limited to transactions for gas utilities. Most of the gas regulators are also electricity regulators, and the criticisms of regulators when dealing with regulated gas entities have also been levelled at regulators in their dealings with regulated electricity entities. Accordingly, assuming regulators are consistent in their treatment of both industries, a test of a regulator's stance for one will provide insight into its stance on the other.

The sample of energy utility transactions that have been examined includes only those where a regulatory asset base had been set at the time of the transaction – either in legislation or through a regulatory approval process – or where a regulatory approval process was underway and at least a draft decision had been released. This implied excluding the Australian Pipeline Trust. The set of entities was also confined to those that were either wholly or substantially price regulated under the Code, or a similar regime, and restructurings of organisations (for example, the transfer of assets into a vehicle to be subsequently listed) have also been excluded. This has meant excluding a number of transactions, including:

- the sale of the State Gas Pipeline in 1996;
- the sale of PowerNet Victoria in 1997;
- the sale of the Dampier to Bunbury Natural Gas Pipeline in 1998;
- the sale of the various interests in the Goldfields Gas Pipeline in late 1998 and early 1999;
- the sale and transfer of the various interests in the Moomba to Sydney Pipeline and the creation of the Australian Pipeline Trust; and
- the creation of Envestra from Boral's former gas transportation interests.

In addition, for practical reasons, the set of listed entities was limited to companies that undertook limited activities outside of their regulated activities, which implied excluding:

- AGL; and
- United Energy.

Accordingly, sample of transactions and entities analysed cover:

- the privatisation of government assets (11 observations, four of which are gas utilities);
- the trade sale of privately-owned entities (2 observations, none of which are gas utilities); and
- listed entities (3 observations, all of which are gas utilities).

Detailed information on all of the enterprises sampled is provided in the Appendix.

Market Value of the Regulated Activity

Where the assumption about the market value of the enterprise is taken from the proceeds for an asset, this information is taken from publicly available sources. In some cases, adjustments have been made to headline numbers, which are discussed in the relevant section in the Appendix. Where a market value is inferred from share prices, an average of the closing prices over the month prior to the particular date is used to establish the value of the equity finance, and the normal assumption is made that the book value of debt provides a reasonable estimate of its market value.

As noted in section 5.2, it is important to adjust the estimated market value for an entity to remove the value associated with activities that are outside of those covered by its price controls, the most important of which for the entities studied in this report are retailing activities.

The Appendix derives a number of benchmarks (expressed in terms of $/customer) for the value of retail businesses from sales of such businesses, which are set out in table 5.1 below. The results presented for the market-to-regulatory value ratio demonstrate the impact of the assumed value of the retail business for a range of retail-value benchmarks of between $200 per customer and $1,000 per customer, and for the highest benchmark observed for either an electricity retailer or a gas retailer (as relevant), adjusted for inflation.

Table 5.1

Transaction	Date	Benchmark ($/customer)
Electricity Retailers		
Sale of CitiPower	July 2002	519
Sale of Powercor	June 2001	404
Sale of United Energy	June 2000	625
Sale of ETSA Power	January 2000	238
Gas Retailer		
Sale of Energy 21	March 1999	878

It should be noted that, for a number of recent transactions, the retail component of a previously integrated business has been sold separately to the distribution component, or the retail business has been sold soon after the initial transaction. These transactions provide observations of the market value of the relevant entity that is not dependent on the assumption that is made about the value of any retail activities.

Regulatory Value of the Regulated Activity

While regulatory asset values are straightforward to compute if the roll-forward method is used (as described in section 3.5) – which is the methodology is used for all of the regulated businesses studied in this report – obtaining an accurate figure for the regulatory value at any point in time is challenging. This is because few regulators publish regulatory asset values between price reviews, and not even all of them publish regulatory asset values at the time of their price review decisions. Moreover, even where the relevant forecasts are provided, a number of regulators adopt the practice of publishing forecasts in nominal terms using their forecast of inflation, which are irrelevant where prices are indexed for actual inflation (as is the case for all regulated entities in Australia).

In this report, the general approach to deriving estimates of the regulatory values of the relevant entities was as follows.

- First, to the extent that calculated (actual) historical values have been presented in regulatory decisions, these are used.
- Secondly, in the absence of calculated figures, then forecasts from the relevant regulatory decision are used, adjusted where possible to reflect actual inflation (rather than forecast inflation) over the period.
- Thirdly, where it is not possible to adjust for any difference between forecast and actual inflation from a regulator's decision, then the nominal figures are used.

This methodology and the data sources relied upon are discussed out in more detail in the Appendix.

Results

The results of the Allen Consulting Group analysis are presented in Tables 5.2 to 5.4, below.

Table 5.2

PRIVATISATIONS

		Transaction	Principal Activities	Gross Sale Value	Basis for Value of Retail Business		Estimated Sale Value of Regulated Business	Regulatory Asset Value (RAV)	Sale Value: Regulatory Value
				($million)		($/customer)	($million)	($million)	
Victorian Electricity Distribution									
30/6/95	Entity	United Energy	Electricity distribution, retail and associated services	1,553	Illustrative range	200	1,450	936	1.5
	Sold by	Vic Govt				600	1,243		1.3
	Sold to	The Power Partnership				1000	1,036		1.1
					Benchmark	580	1,253		1.3
30/9/95	Entity	Solaris	Electricity distribution, retail and associated services	950	Illustrative range	200	902	448	2.0
	Sold by	Vic Govt				600	807		1.8
	Sold to	AGL and GPU				1000	712		1.6
					Benchmark	580	810		1.8
30/9/95	Entity	Eastern Energy	Electricity distribution, retail and associated services	2,080	Illustrative range	200	1,987	906	2.2
	Sold by	Vic Govt				600	1,801		2.0
	Sold to	TXU				1000	1,615		1.8
					Benchmark	580	1,807		2.0
30/9/95	Entity	Powercor	Electricity distribution, retail and associated services	2,150	Illustrative range	200	2,043	1,123	1.8
	Sold by	Vic Govt				600	1,829		1.6
	Sold to	PacifiCorp				1000	1,615		1.4
					Benchmark	580	1,836		1.6
30/9/95	Entity	CitiPower	Electricity distribution, retail and associated services	1,575	Illustrative range	200	1,528	656	2.3
	Sold by	Vic Govt				600	1,434		2.2
	Sold to	Entergy Corporation				1000	1,339		2.0
					Benchmark	580	1,437		2.2

Date	Transaction		Principal Activities	Gross Sale Value	Basis for Value of Retail Business		Estimated Sale Value of Regulated Business	Regulatory Asset Value (RAV)	Sale Value: Regulatory Value
				($million)		($/customer)	($million)	($million)	
Victorian Gas Distribution									
31/1/1999	Entity	Westar/Kinetick Energy	Westar: gas distribution	1,617	Illustrative range	200	1,534	636	2.4
	Sold by	Vic Govt	Kinetic: gas retail			600	1,367		2.1
	Sold to	TXU				1000	1,200		1.9
					Benchmark	878	1,251		2.0
12/3/99	Entity	Multinet/Icon Energy	Multinet: gas distribution	1,970	Illustrative range	200	1,865	733	2.5
	Sold by	Vic Govt	Icon: gas retail			600	1,654		2.3
	Sold to	The Energy Partnership				1000	1,443		2.0
					Benchmark	878	1,507		2.1
13/3/1999	Entity	Stratus Networks/Energy 21	Stratus: gas distribution	1,670	Separate sale or retailer	na.	1,196	614	1.9
	Sold by	Vic Govt	Energy 21: gas retail						
	Sold to	Envestra/Boral Energy							
Victorian Gas Transmission									
7/5/99	Entity	Transmission Pipelines Aust.	Gas transmission	1,025	Analyst estimate (LNG)	$52m	973	479	2.0
	Sold by	Vic Govt							
	Sold to	GPU							
South Australia Electricity Distribution									
12/12/99	Entity	ETSA Utilities/ETSA Power	ETSA Utilities: electricity dist	3,494	Retail business on-sold	n.a.	3,344	2,263	1.5
	Sold by	SA Govt	ETSA Power: electricity retail						
	Sold to	CKI/HEI							
Western Australia Gas Distribution									
1/10/00	Entity	AlintaGas	Gas distribution and retail	971	Illustrative range	200	886	585	1.5
	Sold by	WA Govt				600	717		1.2
	Sold to					1000	548		0.9
					Benchmark	946	570		1.0

Table 5.3

PRIVATE TRADE SALES

Date	Transaction		Principal Activities	Gross Sale Value	Basis for Value of Retail Business		Estimated Sale Value of Regulated Business	Regulatory Asset Value (RAV)	Market Value: Regulatory Value
				($million)		($/customer)	($million)	($million)	
Victorian Electricity Distribution									
22/11/1998	Entity	CitiPower	Electricity distribution, retail and associated services	1,700	Illustrative range	200	1,651	702	2.4
	Sold by	Entergy Corporation				600	1,554		2.2
	Sold to	AEP				1000	1,457		2.1
					Benchmark	609	1,552		2.2
15/9/2000	Entity	Powercor	Electricity distribution, retail and associated services	2,315	Retail business on-sold	n.a.	2,007	1,428	1.4
	Sold by	Scottish Power							
	Sold to	CKI/HEI							
01/9/2002	Entity	CitiPower	Electricity distribution, retail and associated services	1,555	Retail business on-sold	n.a.	1,418	894	1.6
	Sold by	AEP							
	Sold to	CKI/HEI							

Table 5.4

LISTED ENTITIES

Listed Entity	Principal Activities	Market Value of Listed Entity		Basis for Value of Retail Business		Estimated Market Value of Regulated Business	Regulatory Asset Value (RAV)	Market Value: Regulatory Value
		Date	($million)		($/customer)	($million)	($million)	
Envestra	Distribution of natural gas in South Australia, Victoria (including Mildura), Queensland, Alice Springs and New South Wales (Albury)	30/6/2001	2,259	n/a		2,259	1,683	1.3
		31/12/2001	2,352			2,352	1,644	1.4
		30/6/2002	2,273			2,273	1,678	1.4
		31/12/2002	2,443			2,443	1,710	1.4
AlintaGas	Distribution and retail of natural gas in Western Australia	30/6/2001	967	Illustrative range	200	878	601	1.5
					600	701		1.2
					1000	524		0.9
				Benchmark	964	540		0.9
		31/12/2001	941	Illustrative range	200	852	609	1.4
					600	673		1.1
					1000	493		0.8
				Benchmark	976	504		0.8
		30/6/2002	1,058	Illustrative range	200	968	618	1.6
					600	788		1.3
					1000	608		1.0
				Benchmark	992	612		1.0
		31/12/2002	1,016	Illustrative range	200	924	626	1.5
					600	741		1.2
					1000	558		0.9
				Benchmark	1005	555		0.9
GasNet	Transmission of natural gas in Victoria	31/12/2001	829	Analyst Estimate	$57m	772	497	1.6
		30/6/2002	807	(LNG)	$58m	749	495	1.5
		31/12/2002	859		$59m	799	494	1.6

From the information presented above, it is clear that the market value of the regulated activities has exceeded the regulatory value almost universally. It is also clear that the market values have typically exceeded the regulatory values by a substantial margin.

Of the transactions or listed entities covered, the only ones for which the market-to-regulatory value was close to unity were for United Energy and AlintaGas, but only if a high value for their retail activities is assumed. At the other end of the scale, a number of businesses have paid either close to – or in excess of – twice of the regulatory value. Included in this set are all of the Victorian gas distributors, which were sold after an access arrangement had been approved by an independent regulator. However, in more recent times, the observed market-to-regulatory values have appeared to have ranged between about 1.4 times and 1.6 times.

Many of the transactions analysed in this chapter have taken place in an environment where the stance of regulators has been well known. While the practice of price cap regulation – and the relationship between prices and cost – was well established prior to any of these assets being sold, many have argued that the position of regulators on important matters like the cost of capital had not been known at the time of some asset sales.

We do not necessarily accept these views – after all, investors and equity analysts form a view on the cost of capital associated with an asset every day, and a regulator reasonably could be expected to undertake a similar exercise to that undertaken by market participants. However, with the exception of the initial privatisation of the Victorian electricity distributors, all of the transactions and observations in the table above occurred after regulator's had expressed in detail their views on regulation in general and specifically on the cost of capital associated with regulated activities.[72] Indeed, the privatisation of all five of the gas businesses in the table – the three Victorian gas distributors, the Victorian transmission company and the WA gas distributor – all occurred after an access arrangement for the business had been approved by the relevant regulator.

The existence of a ratio of the market-to-regulatory value ratio of more than one has been noted by many other parties. Moreover, even regulated entities have also recognised this empirical regularity between the market and regulatory values of assets in Australia. For example, in a recent submission to the Independent Gas Pipelines Access Regulator, Epic Energy undertook its own empirical analysis, and summarised its results as follows:[73]

> Where assets have been acquired, or where shares have been traded, the value placed on a regulated business is consistently higher than the value assigned by the regulatory process. In this context, Epic Energy's situation – purchase price 2.1 times the DORC – is not an aberration resulting from injudicious purchase. It is the norm. In a large number of independent transactions, purchase prices have been about double regulated asset value. The divergences between purchase price and regulated asset value are clearly not the random divergences that would be expected on the assumption of the irrational exuberance of the purchasers of regulated assets.

[72] The relevant decisions are: Office of the Regulator-General, 1998, Access Arrangements for Multinet, Westar and Stratus: Draft Decision, May; Australian Competition and Consumer Commission, 1998, Access Arrangement for Transmission Pipelines Australia and VENCorp: Draft Decision, May.

[73] Epic Energy, Court Additional Paper 1 – CDAP#1: Response to AlintaGas Submission, February 2003, pp.28-29.

The implications of this observed premium of market value over regulatory value are discussed below.

5.4 Implications of the Premium of Market Value over Regulatory Value

The clear conclusion from the evidence discussed above is that investors do not expect to be rewarded under the regulatory regime for providing the regulated services at less than the cost of providing those services. Rather, the evidence demonstrates that investors expect returns on their regulated assets that exceed – and exceed by a margin – the returns required to attract and retain capital in the industry.[74]

This conclusion also has important implications for the conditions for investment in the types of activities covered by this analysis. Provided that the relationship described above holds for new assets in the same proportion to existing assets – which seems a reasonable assumption – then, far from deterring investment, the rewards available for investing in the regulated services exceed those required. That is, more than enough incentive to invest exists. In simple terms, $1 invested in the business would be transformed into between approximately $1.40 and $1.60 – which is an option that a business interested in maximising shareholder returns logically would take.

It follows that no empirical support can be found for the view that the stance of regulators provides a threat to new investment in these activities, that regulators are 'too ambitious' when setting regulated charges, or that regulators consistently adopt forecasts that are biased towards the interests of the customers. Indeed, to the extent that a conclusion can be drawn from this analysis, it is that the opposite bias in decisions is demonstrated.

The reason for the difference between the market and regulatory values of regulated assets cannot be discerned from the analysis undertaken in this chapter as regulated charges – and the market values of the relevant asset – both reflect the totality of the assumptions adopted. However, the cost of capital that a regulator assumes when setting regulated charges has a substantial effect on the resulting charges and revenues, and hence the value of the asset. It is notable that there has been once instance where a regulator has examined in detail the financial considerations of a pipeline owner in the purchase of an asset, this being the purchase of the Dampier to Bunbury Natural Gas Pipeline by Epic Energy. The conclusion drawn by the Independent Gas Pipelines Access Regulator was as follows.[75]

> The Acquisition Model suggests that the difference between the price paid for the DBNGP ($2,407 million) and the assumed regulatory value ($1,100 million) can in large part be explained by the assumption that a future regulator would approve a regulatory rate of return well in excess of the cost of capital implicitly assumed by the investors in the DBNGP assets.

[74] This conclusion needs to be read subject to the caveat about the wider applicability of these results that was set out at the start of this section.

[75] Independent Gas Pipelines Access Regulator Western Australia, 23 May 2003, Final Decision, Proposed Access Arrangement, Dampier to Bunbury Natural Gas Pipeline, para 248.

Accordingly, the observation of a large wedge between the market value of an asset and its regulatory value makes it highly unlikely that regulators could be understating the cost of capital associated with the regulated activities of the relevant business. Rather, the more likely outcome is that regulators systematically err in favour of providing regulated entities with a return that exceeds the cost of capital associated with the relevant activities. Such an explanation would appear consistent with the views of some market practitioners.

> … the regulator, in this analyst's opinion, continues to be quite generous in his allowed cost of capital, if only because the allowed equity risk premium of 6% is higher than JP Morgan's estimate of 4%.
>
> JP Morgan, 5 July 2002 (note on Envestra), p.2

Appendix A

Methodology for estimating market and regulatory asset values

A.1 Introduction

This appendix provides further explanation of the derivation of the market and regulatory asset values of regulated electricity and gas transmission and distribution businesses in Australia that were presented in chapter 5.

The asset sale transactions that are analysed in this report are the:

- Victorian electricity retail and distribution privatisations in 1995 (five businesses);
- Victorian gas retail and distribution privatisations in 1999 (three businesses);
- Victorian gas transmission privatisation in 1999 (one business);
- South Australian electricity retail and distribution leasing and sale in 1999/2000 (one business);
- West Australian gas retail and distribution privatisation in 2000 (one business); and
- Three subsequent trade sales of Victorian electricity retail and distribution businesses.

It is estimated that the total proceeds for all of these assets (including the value of non-network activities) was about $25 billion.[76] In addition, the implied market value from three listed entities is also analysed, which are:

- Envestra (for the period from 30 June 2001 to 31 December 2002);
- AlintaGas (for the period from 30 June 2001 to 31 December 2002); and
- GasNet (for the period from its listing on 17 December 2001 to 31 December 2002).

These assets have a combined market value (including the value of debt) of approximately $4.3 billion at present.

A.2 Methodology for Deriving Market, Regulatory and Retail Values

Methodology for deriving market asset values

Market values were determined from data generated by sales of the relevant assets and businesses, or by the prices observed for trades for the rights to ownership of interests in the assets.

[76] This figure has not been adjusted for inflation.

Information on proceeds from trade sales were taken from a variety of published sources.

For listed entities:

- The *value of the equity* at the end of the relevant month has been taken as the number of shares on issue, multiplied by the simple average of the end-of-day share price within that calendar month (that is, the value as at 31 June has used the average share price for June).
- The *value of the debt* on issue has been taken as the sum of the book value of short term and long term interest bearing liabilities, less the book value of the loan note principal. The value of the loan notes on issue, in turn, has been calculated as the number of shares on issue, multiplied by the loan note balance (per share).
  - Two sources have been used to derive the book values of short and long term interest bearing liabilities. The values as at the end of financial years (end June) have been taken from Annual Reports and the mid-financial year values have been taken from ASIC half-year accounts.

Methodology for deriving regulatory asset values

Estimating a regulatory asset value at a point in time requires two steps, which are to:

- arrive at an opening value that reflects the assets in existence at a point in time; and
- then to adjust (or 'roll-forward') that value to reflect new capital additions (an increase in the regulatory asset value), the portion of capital that has been returned to investors (depreciation – a reduction in the regulatory asset value) and asset disposals (a reduction in the regulatory asset value).

In addition, the universal practice when determining price controls in Australia for energy utilities is to set prices that would be expected to provide the required *real* rate of return to the investors (that is, the return that is required above the expected rate of inflation). Investors are then compensated for inflation by escalating prices for actual inflation (proxied by one of the available price indices – such as the Consumer Price Index), which implies that the underlying assets are also escalated for inflation. The escalation of the value of the assets for inflation happens *implicitly* during a regulatory period, and *explicitly* when prices are formally reviewed. Accordingly, the process of rolling-forward the regulatory asset value also needs to escalate the asset value for actual inflation over time.

Transactions or entities have only been examined where a value has been set in a legislative instrument, determined by a regulator, or where the valuation of assets currently is subject to regulatory approval process. The following general approach has been taken to estimate the regulatory values at the time of the relevant transaction.

- *Starting values* – where a starting value has been determined by legislative instrument, or determined by a regulator, that value has been used. If the value is currently the subject of a regulatory approval process and the regulator has issued a *Draft Decision*, then the value determined in the *Draft Decision* has

been used. Otherwise, the regulated entity's proposal for the regulatory asset value has been used.

- *Capital expenditure and depreciation* – where public information on actual capital expenditure is available, this is used to roll-forward the regulatory values. Otherwise the following priority is adopted (with the choice depending upon the information available):

  — The forecasts of capital expenditure that were adopted by the regulator for the purpose of determining the current price controls;

  — The capital expenditure forecasts proposed by the regulated entity during the previous price review;

  — Where no information is available, capital expenditure and depreciation have been assumed to be equal.

- Regulatory depreciation is always taken as the return of capital that was assumed when the existing price control were determined (that is, it is assumed that this amount would be taken off of the regulatory value regardless of what happens over the regulatory period). If the assumption about regulatory depreciation is not available, then it is assumed that capital expenditure and depreciation are the same.

- Calculations have been undertaken in constant price terms, with adjustment for actual inflation over the relevant period applied at the last step if possible. However, where the information provided by the regulator has made this task excessively difficult, nominal values have been used (with the implicit assumption that forecast and outturn inflation have been the same).

- The adjustment for inflation uses the *Consumer Price Index (Average of the Eight State Capitals)*, and the price index. Where relevant, it is assumed that all regulators would permit the whole of the increase in the CPI that accompanied the introduction of the GST to pass through into the regulatory asset base (rather than to remove the GST-related element from the measure of inflation).

- Regulatory values are estimated on a quarterly basis to permit a better alignment with the timing of the transactions. For this purpose, it is assumed that the expenditure is incurred at a constant rate during each year (except in relation to Transmission Pipelines Australia, where certain major increments are assumed to have entered the regulatory asset base at discrete times).

Methodology for Estimating the Value of Retail Activities

The estimates of the value of the retail businesses have been derived from benchmarks for the value of retailers from sales of retail-only businesses. When using benchmarks from the sale of retailers, it is necessary to adjust for known factors that may influence the value of the different retail business. A key factor that will influence the value of a retail business is the number of customers, and potentially the types of customers served. In addition, the value of a retail business may also be affected by whether the retailer has franchise customers for a period of time and the characteristics of the retail price regulation in place for that period (including whether the regulatory arrangements may permit economic rents to occur), the proposed arrangements for retail contestability in the relevant industry, as well as the proposed arrangements (or likelihood of) retail contestability in related industries (for example, a gas retail business may be more valuable if it is considered that expansion into electricity retailing is possible).

However, the information required to develop sophisticated benchmarks does not exist, and so simple *$ per customer* benchmarks have been used. That is, customer numbers have been assumed to be the sole explanatory variable, and the value of a retailer is assumed to be given by the number of customers multiplied by the number of customers.

There are four electricity transactions that can be used to infer such a benchmark for electricity retailing:

- The sale of Citipower's retail business to Origin Energy in July 2002. Origin Energy paid $137 million for a business with 264,000 customers, implying a benchmark of $519 per customer.[77]
- The sale of Powercor's retail business to Origin in June 2001. Origin paid $315 million, but claimed that $80 million was the value of hedge positions.[78] Using the value that is net of the value of the hedges ($235 million), and the customer numbers quoted in its media release,[79] implies a benchmark of $404 per customer.
- United Energy's contribution of its retail electricity business to Pulse Energy in June 2000. In its annual report it stated that it received $350 million for the sale of its electricity retail customer base.[80] Using the customer numbers stated in its press release announcing the formation of Pulse Energy of 560,000,[81] this implied a benchmark value for its retail business of $625 per customer.
- The sale of ETSA Power (the SA electricity retailer) from CKI/HEI to AGL in January 2000 for $175 million. Using the customers numbers quoted in AGL's press release of 734,000,[82] implies a benchmark of $238 per customer.

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77 Origin Energy to acquire Citipower electricity retail business, Origin Energy Press Release, 19 July 2002.

78 'Acquisition of Powercor's Retail Business', Briefing to the Investment Market, 17 April 2001, Grant King, Managing Director.

79 Origin Energy, Origin Energy to Acquire Powercor Electricity Retail Business, Media Release, 12 April 2001. Origin Energy stated in its presentation to investors that it had bought the business as a price of $400 per customer, which provides some validity to the use of a per customer benchmark.

80 United Energy, Concise Annual Report 2000, page 14.

81 United Energy, Energy Partnership, Shell Australia and Woodside, New National Energy Retailer Announced, Media Release, 8 March 2000.

82 AGL, 'AGL Adds 734,000 Electricity Customers in South Australia, Media Release, 14 January 2000.

There is one transaction that can be used to infer a benchmark for gas retailing, which is Boral's purchase of the Energy 21 gas retailing business (in the initial privatisation) in March 1999. Using the purchase price of $473 million, and the customer numbers quoted in Boral's investor presentation immediately after the sale of 540,000,[83] implies a benchmark of $878 per customer.

After adjusting for inflation, the following valuation benchmarks are derived for electricity and gas retailers.

	Electricity Retailer Benchmarks ($/customer)				**Gas Retailer Benchmark**
Value as at:	*AGL's Purchase of ETSA Power*	*Origin's Purchase of Citipower Retail*	*Origin's Purchase of Powercor Retail*	*United Energy's proceeds from Pulse*	*Boral's Purchase of Energy 21*
31-Dec-95	226	447	358	592	854
31-Dec-96	229	454	363	601	867
31-Dec-97	229	453	362	599	865
31-Dec-98	232	460	368	609	878
31-Dec-99	236	468	375	620	894
31-Dec-00	250	495	396	655	946
31-Dec-01	258	511	409	676	976
31-Dec-02	266	526	421	696	1005

Given the range of the benchmarks, the implications benchmarks of $200 per customer, $600 per customer and $1000 per customer are shown, as well as the implications of the highest of the electricity benchmarks (that implied by the Pulse transaction) and the benchmark for gas implied by Boral's purchase of Energy 21.

For the purpose of applying benchmarks for the value of retailers, estimates of customer numbers are used that are considered as close as possible to the numbers of customers at the time of sale.

A.3 Privatisations

Victorian Government Electricity Distribution Privatisations

Principal Activities of the Businesses

All of the companies retail and distribute electricity within their licence areas. The retailers were initially exclusive franchises, which were to be gradually exposed to competition (with full retail contestability on 1 January 2000). The specific characteristics of the five businesses at the time of privatisation (in the order of sales) were as follows.[84]

[83] Boral, 'What We Bought and How Much We Paid' Boral Energy 21 Analyst Presentation, 16 March 1999.

[84] All of this information (except for customer numbers) is taken from: Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, Paragraph 3.8.50. Customer numbers are taken from Office of State Owned Enterprises (Department of the Treasury), Reforming Victoria's Electricity Industry: A Competitive Future for Electricity, December 1994, page 41, which are as at 30 June 1994.

- *United Energy* – The company distributes and retails electricity. Its distribution network covers approximately 1,450 square kilometres in the south-eastern suburbs of the Melbourne metropolitan area, extending to the semi-rural and coastal resort area of the Mornington Peninsula. This region accounts for 26 per cent of Victoria's population. The company distributes and retails power to 517,714 customer sites.
- *Solaris* – the company distributes and retails electricity to the north-western suburbs of Melbourne. Its distribution network covers an area of approximately 956 square kilometres and includes the municipalities of Williamstown in the south through to Heidelberg in the east and includes the communities of Broadmeadows and Sunbury. It retails and distributes electricity to over 233,240 customer sites.
- *Eastern Energy* – the company serves predominantly regional and rural areas comprising 80,000 square kilometres from the outer-Eastern Melbourne metropolitan area to the eastern coastal areas and the Victoria/New South Wales border to the north. Eastern Energy currently distributes and retails to 457,937 customer sites.
- *Powercor* – the company is geographically the largest distribution business in Victoria. Its retail and distribution area covers approximately 150,000 square kilometres in central and western Victoria and accounts for over one third of Victoria's population. The company supplies electricity to seven of the eight largest Victorian regional cities, including Geelong. The company retails and distributes power to 526,080 customer sites.
- *CitiPower* – the company's distribution area is the smallest of the 5 distributors, covering approximately 157 square kilometres. The area includes the central business district and the densely populated inner suburbs of Melbourne. CitiPower has the highest customer density, with 1,468 customers per square kilometre and the highest market share in the commercial sector, with 34 per cent of total commercial sales in Victoria. The company retails and distributes to about 230,822 customers.

Purchasers and Sale Proceeds

The purchasers of the businesses were:

- *United Energy* – the Power Partnership, which comprised the AMP Society, the State Authorities Superannuation Board of NSW, and Utilicorp (a US utility company);
- *Solaris* – a consortium comprising the Australian Gas Light Company (50%) and General Public Utilities (50%, a US utility company);
- *Eastern Energy* – Texas Utilities (a US utility company);
- *Powercor* – PacifiCorp (a US utility company); and
- *CitiPower* – Entergy (a US utility company).

The *up-front proceeds* received for the sale of these entities were as follows:

Business	Date Announced	Financially Effective[85]	Proceeds ($m)[86]
United Energy	7 August 1995	30 June 1995	1,553
Solaris	30 October 1995	30 September 1995	950
Eastern Energy	5 November 1995	30 September 1995	2,080
Powercor	16 November 1995	30 September 1995	2,150
CitiPower	14 December 1995	30 September 1995	1,575

It should be noted the Auditor-General released different figures for the proceeds from these sales that were not (and are not readily) reconciled to these figures.[87] However, the difference in the figures (which were less than +/– $40 million in all cases) does not change the results, and so the figures drawn from the official government publication are used.

In addition to the up-front capital payments, a further condition of the sale for all businesses except for Powercor was that the businesses would pay franchise fees over the period until full retail contestability. The present value of these franchise fees at the time of the sales were as follows:[88]

Business	Franchise Fees ($m, PV)
United Energy	275
Solaris	137
Eastern Energy	47
Powercor	nil
CitiPower	173

The Government's intention in setting the franchise fees were to extract the monopoly rent element of the regulated prices to franchise customers that was to exist until full retail contestability:

> The franchise fee is designed to capture excess profits that would otherwise accrue to [retailer/distributors] as a result of setting [Maximum Uniform Tariffs] across Victoria which are in excess of the cost of supplying electricity to franchise customers, including a fair return on assets.
>
> …
>
> The franchise fee captures for Government the "monopoly rent that would otherwise be available to the [retailer/distributors].[89]

---

85 Taken from: Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, Paragraphs 3.8.56-3.8.64.

86 Department of the Treasury, Victoria's Electricity Supply Industry: Towards 2000, June 1997, page 8.

87 Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, Table 3.81.

88 Office of the Premier of Victoria, 'Government Announces Sale of United Energy, 7 August 1995; Office of the Premier of Victoria, 'Government Announces Sale of Solaris, 30 October 1995; Office of the Premier of Victoria, 'Government Announces Sale of Eastern Energy, 5 November 1995; Office of the Premier of Victoria, 'Government Announces Sale of Powercor for $2.15 billion, 16 November 1995; Office of the Treasurer of Victoria, 'Government Finalises Sale of CitiPower, 14 December 1995. The present value of the franchise fees reported here coincide with those reported by the Auditor-General: Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, table 3.8G.

89 Office of State Owned Enterprises (Department of the Treasury), Reforming Victoria's Electricity Industry: A Competitive Future for Electricity, December 1994, page 80. No franchise fee was payable

For the purpose of this exercise, the sale proceeds have been taken as the *up-front capital payments* only. It is noted that this assumption has implications for the estimation of the value of the retail component of the business, which is discussed further below.

Information on the Spread of Bids

There is little information publicly available (by the Government or the Auditor-General) on the *spread* of the bids for these businesses. The only indicators found were:

- Of the three firm offers received for Eastern Energy in August 1995, two were very close, and the bidders were asked to reconsider the financial aspects of their bids.[90]
- Similarly, of the five pre-emptive offers for Powercor in November 1995, two were very close, and the bidders were asked to reconsider the financial aspects of their bids.[91]

Value of Retail Businesses

Results have been presented for the range of plausible benchmarks for the value of retail businesses (in $/customer terms), as discussed in section A.2.

The franchise fees described above *have not* been included as part of the sale proceeds for the Victorian electricity distribution businesses. Rather, these fees are assumed to remove the monopoly rent element that otherwise would have been received by four of the five businesses, in turn implying that the bid price for the retail business should not have reflected the value of future monopoly rents. As a consequence, it is valid to use benchmarks for retail business valuations that have been derived from transactions involving firms that operate in contestable markets.

Derivation of the regulatory values, and regulatory regime

The starting regulatory values for the distribution businesses were prescribed in a statutory instrument prior to the sales of the businesses.[92] These values have been updated using information presented in the then Office of the Regulator-General's draft and final decisions on the price controls for the Victorian electricity distributors in 2000.[93]

The regulatory values adopted were those that corresponded to the end of quarter dates at which the transactions were financially effective.

Results

The following ratios of market-to-regulatory values are derived for the range of retail business value benchmarks.

by Powercor due to low forecast retail margins: Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, table 3.8G, note b.

90 Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, paragraph 3.8.60.

91 Victorian Auditor-General, Report on Ministerial Portfolios, May 1996, paragraph 3.8.62.

92 Victorian Electricity Supply Industry Tariff Order, issued by the Governor in Council under section 158A of the Electricity Industry Act 1993 (Vic), June 1995.

93 Office of the Regulator-General, 2001 Electricity Distribution Price Review – Draft Decision, May 2000; Office of the Regulator-General, Electricity Distribution Price Determination 2001-2005, Volume 1, Statement of Reasons and Purpose, September 2000.

Business	Estimated RAV	MV / RAV			
		Retail = $200/cust	*Retail = $600/cust*	*Retail = $1000/cust*	*Retail = $580 to $587/cust*
United Energy	936	1.5	1.3	1.1	1.3
Solaris	448	2.0	1.8	1.6	1.8
Eastern Energy	906	2.2	2.0	1.8	2.0
Powercor	1,123	1.8	1.6	1.4	1.6
CitiPower	656	2.3	2.2	2.0	2.2

Victorian gas distribution privatisations

Principal Activities of the Businesses

The gas distributions businesses were sold as a 'stapled' pair comprising a retail business and the distribution business. The retailers started with exclusive franchises, which were to be gradually exposed to competition (with full retail contestability on 1 September 2001).[94] The retailers' licence areas were only partly coincident with their distribution areas (the share of each distributors' customers that were also customers of its stapled retailer ranged between about 50 per cent and 55 per cent across the three distribution businesses).[95] The specific characteristics of the five businesses at the time of privatization (in the order of sales) were as follows.[96]

- *Westar* owns and maintains approximately 7,500 kilometres of distribution pipelines and associated assets. The business services approximately 412,000 customers in the western and north-western metropolitan area of Melbourne, together with 19 country localities in central and western Victoria. *Kinetik Energy Pty Ltd* sells natural gas and tempered liquefied petroleum gas (TLPG) to approximately 398,000 customers. It also provides associates services, such as gas and electricity connections, energy audits for business and appliance repair.
- *Multinet Gas Pty Ltd* owns and maintains around 8,900 kilometres of distribution pipelines and associated assets. The business services approximately 587,000 customers in the inner, outer eastern and south-eastern suburbs of Melbourne. *Ikon Energy Pty Ltd* sells natural gas to around 504,000 customers. The business also offers other energy services, including energy audits for businesses and an energy advisory service.

[94] Department of the Treasury, Victoria's Gas Industry: Implementing a Competitive Structure, Information Paper No. 3, April 1998, page 30.

[95] Department of the Treasury, Victoria's Gas Industry: Implementing a Competitive Structure, Information Paper No. 3, April 1998, pages 34, 37 and 40.

[96] Except for customer numbers, this is taken from: Victorian Auditor-General, Victorian Government Finances 1998-99, Paragraph 6.33. Customer numbers are taken from Department of the Treasury, Victoria's Gas Industry: Implementing a Competitive Structure, Information Paper No. 3, April 1998, pages 29 and 32, and are assumed to represent estimates of the customers as at 31 March 1998 (consistent with the estimates provided of the Albury Gas Company customers).

- *Stratus Networks Pty Ltd* owns and maintains approximately 7,980 kilometres of distribution and transmission pipelines and associated assets. The business services around 419,000 customers in the central business district, the inner suburban, northern and south-eastern areas of metropolitan Melbourne, the Mornington Peninsula and the eastern, central and northern areas of country Victoria, and in Albury. *Energy 21 Pty Ltd* sells natural gas to around 516,000 customers (which includes Albury). The business also provides connection services for natural gas and electricity, and other services such as energy audits for businesses.

Purchasers and Sale Proceeds

The purchasers of each of the businesses were:

- *Westar/Kinetik* – Texas Utilites (a US utility company);
- *Multinet/Ikon* – The Energy Partnership, which comprised AMP (50%) and Utilicorp (50%).
- *Stratus/Energy 21* – Boral Energy and Envestra.

The proceeds received by the Government for these sales were as follows:

Business	Date Announced	Proceeds ($m) [97]
Westar/Kinetik	31 January 1999	1,617
Multinet/Ikon	12 March 1999	1,970
Stratus/Energy 21	13 March 1999	1,670

There were no franchise fees payable by the gas distribution businesses.

Information on the Spread of Bids

There is no information on the spread of the bids for the Westar/Kinetik and Multinet/Ikon 'stapled' pairs.

However, the Auditor-General noted that the winning bidder of the Stratus/Energy 21 was the *second highest bidder*. The Energy Partnership bid the highest price ($1,730 million). However, as the Energy Partnership had already bought the Multinet/Ikon business, the pre-established cross-ownership rules prevented it from gaining control of the Stratus/Energy 21. As a result, the second highest bidder (whose bid was $60 million below that of The Energy Partnership) was selected.

[97] Office of the Treasurer of Victoria, 'Gas Sale to Boost Energy Competition', 31 January 1999; Office of the Treasurer of Victoria, 'Multinet/Ikon Gas Sale to Increase Benefits for Customers', 12 March 1999; Office of the Treasurer of Victoria, 'Australian Companies Buy Third Gas Business', 13 March 1999. These proceeds are identical to those subsequently reported by the Auditor-General: Victorian Auditor-General, Victorian Government Finances, 1998-99, Table 6G.

Value of the Retail Businesses

While the Stratus/Energy 21 business was sold to a consortium involving Envestra and Boral, the network business was transferred to Envestra,[98] and the retail business to Boral, and both entities disclosed the prices that they paid for their respective businesses.

- Envestra stated that it paid approximately $1,196 million for Stratus Networks,[99] and Boral stated that it paid approximately $474 million for the retail business.[100]

Accordingly, the analysis in this report adopts $1,196 million as the purchase price for the Stratus Networks business.

For the remaining stapled entities, the implied value of the regulated activities is demonstrated for the range of benchmarks for the value of the retail business (in $/customer terms), as discussed in section A.2.

Derivation of the regulatory values, and regulatory regime

The starting regulatory values for all of the distribution businesses' regulated assets (except for Stratus' Albury Gas Company business) had been determined by the Office of the Regulator-General under the *Victorian Third Party Access Code for Natural Gas Pipeline Systems* prior to the sale of the assets.[101] The regulatory value for the Albury Gas Company was determined by the Independent Pricing and Regulatory Tribunal of NSW in late 1999,[102] although the value determined was virtually identical to that proposed by the provider prior to the privatisation.[103]

The regulatory values for the gas distributors over the first regulatory period – including the Albury Gas Company – were set out in the Essential Service's decision on the review of the access arrangements for these companies,[104] and so the values set out in that decision have been used.

The public information on the sale did not disclose the date at which the transactions were financially effective, and so the regulatory values as at the end of March 1999 (the quarter in which all of the transactions took place) have been used.

Results

The following ratios of market-to-regulatory values are derived for the range of retail business value benchmarks.

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98 As discussed further below, Envestra only invests in gas transportation infrastructure, and does not retail gas.

99 Envestra, *1999/00 Annual Report*, page 42.

100 Boral, 'Boral And Envestra Win Victorian Gas Bid' Media Release, 13 March 1999; Boral, Boral Energy 21 Analyst Presentation, 16 March 1999 (www.boral.com.au/news/news1999/news47.htm).

101 Office of the Regulator-General, *Access Arrangements – Multinet Energy Pty Ltd & Multinet (Assets) Pty Ltd, Westar (Gas) Pty Ltd & Westar (Assets) Pty Ltd, and Stratus (Gas) Pty Ltd & Stratus Networks (Assets) Pty Ltd: Final Approval*, 17 December 1998;

102 Independent Pricing and Regulatory Tribunal of NSW, Final Decision, Access Arrangement, Albury Gas Company Limited, 3 December 1999.

103 The Albury Gas Company is estimated to have comprised about 3.5% of the regulatory value of Stratus' assets at the time of purchase.

104 Essential Services Commission, 2003 Review of Gas Access Arrangements: Final Decision, October 2002.

Business	Estimated RAV	MV / RAV			
		Retail = $200/cust	*Retail = $600/cust*	*Retail = $1000/cust*	*Retail = $878/cust*
Westar	636	2.4	2.1	1.9	2.0
Multinet	733	2.5	2.3	2.0	2.1
Stratus	614			1.9	

Victorian Gas Transmission Privatisation

Principal Activities of the Business

Transmission Pipelines Australia (TPA) owned and maintained the high-pressure gas transmission system in Victoria, including associated facilities, such as compressors, metering stations and regulator stations. At that the time of privatisation, it was operated as two separate systems, which were knows as the principal transmission system (PTS), and the western transmission system (WTS). It also owned a share of the pipeline connecting the Victorian transmission system to the Moomba-Sydney pipeline (the interconnect). At the time of privatisation, TPA was constructing a pipeline to the south-west to link with an underground storage facility, and to link the PTS and WTS.

However, Transmission Pipelines Australia did not operate its transmission system. This was undertaken by an independent entity, Victorian Energy Networks Corporation (VENCorp), whose activities were governed by the Victorian Market and System Operating Rules.

Purchaser and Sale Proceeds

Transmission Pipelines Australia was sold to General Public Utilities (a US utility company) for $1,025 million, which was announced on 7 May 1999.[105] There were no franchise fees payable by Transmission Pipelines Australia.

Information on the Spread of Bids

There is no information available publicly on the spread of bids.

Value of any other businesses

Transmission Pipelines Australia had a half share in the LNG facility at Dandenong at the time of the privatisation. This was estimated by an equity analyst to have a market value of $60 million in March 2003,[106] which has been adjusted for inflation to provide an estimate of the market value of this activity at the time of privatisation.

[105] Office of the Premier of Victoria, '$1.025 billion Pipeline Sale Completes Victorian Gas Privatisations', 7 May 1999. These proceeds are identical to those subsequently reported by the Victorian Auditor-General: Victorian Auditor-General, Victorian Government Finances1998-99, Table 6G.

[106] Source: JP Morgan Asia Pacific Equity Research, Infrastructure and Utility Directions, Part B, 14 April 2003.

Derivation of the regulatory values, and regulatory regime

As with the gas distribution businesses, the starting regulatory value for Transmission Pipelines Australia's assets were determined by the Australian Competition and Consumer Commission prior to the sale of the assets.[107] The ACCC set the rolled-forward regulatory value for the company in its subsequent review of the access arrangement for the entity, and hence these values have been used in the analysis.[108]

The public information on the sale did not disclose the date at which the transaction was financially effective, and so the regulatory value as at the end of June 1999 (the quarter in which the transaction took place) has been used.

It is noted that $91.8 million in capital expenditure relating to asset's known to have entered into service prior to GPU's purchase in May 1999 have been incorporated in the regulatory asset value as at May 1999, rather than assumed to be spread over the year.

Results

The figures discussed above imply the following ratio of the market-to-regulatory value.

[107] Australian Competition and Consumer Commission, Final Decision: Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System, Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System, and Access Arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, 6 October 1998.

[108] Australian Competition and Consumer Commission, GasNet Australia – Access Arrangement Revisions for the Principal Transmission System: Final Decision, November 2002.

Business	Estimated RAV	MV / RAV
Transmission Pipelines Australia	**479**	**2.0**

South Australian Electricity Distribution Privatisation

Principal Activities of the Business

The *electricity distribution* functions of the former Electricity Trust of South Australia (ETSA) were allocated to ETSA Utilities, a lease to operate the assets for 200 years was sold. The *electricity retailing* functions of the former ETSA were allocated to ETSA Power, which were to be to be sold. The interests in the distributor and the retailer were sold as a pair.

Purchaser and Sale Proceeds

The 200 year lease in ETSA Utilities was awarded, and ETSA Power was sold, to a consortium comprising Hong Kong Electric Holdings (50%) and Cheung Kong Infrastructure (50%).

The cash purchase price for the interests in the two businesses was $3,400 million. In addition, the companies also agreed to accept an unfunded superannuation liability that was valued at $94 million.[109] The implications of the unfunded superannuation liability for the purchase price were described by the purchasers as follows:

> Total consideration of the acquisition is AUS$3.4 billion (approx. HK$16.8 billion). An additional AUS$94 million superannuation, which would otherwise be the government's responsibility, has been included in the government's valuation. The superannuation is to be a part of the venture's future operating cost and has been factored into the AUS$3.4 billion.[110]

Thus, the existence of the liability would appear to have reduced their bid price. As a consequence, it is appropriate to include the value of the unfunded superannuation liability as part of the purchase price. The proceeds for the interests in the two businesses are therefore taken as $3,494 million.

While the transaction was not completed until 28 January 2000, it had financial effect from the date of announcement (12 December 1999).[111] Accordingly, the estimated regulatory asset value as at 31 December 1999 is used in calculations.

Information on the Spread of Bids

No information was found on the spread of bids.

[109] Premier of South Australia, 'Hutchinson Company Wins Right to Lease ETSA', 12 December 1999; Cheung Kong Infrastructure, 'Cheung Kong Infrastructure and Hong Kong Electric "Going Global"', Media Release, December 1999.

[110] Cheung Kong Infrastructure, 'Cheung Kong Infrastructure and Hong Kong Electric "Going Global"', Media Release, December 1999.

[111] Premier of South Australia, 'Hutchinson Company Wins Right to Lease ETSA', 12 December 1999.

Value of any other businesses

Prior to the completion of the privatisation sale of the interests in ETSA Utilities and ETSA Power, Hong Kong Electric and Cheung Kong Infrastructure ran a competitive tender for the sale of the retailing business (ETSA Power). AGL was the winning bidder, paying $175 million for the business.[112]

However, under its sale contract with the South Australian Government, the Hong Kong Electric and Cheung Kong Infrastructure consortium agreed that if ETSA Power were sold within two years after the award of the tender (12 December 1999), any amount generated in addition to $150 million would belong to South Australian Government.[113]

As a consequence, the proceeds received by the Hong Kong Electric and Cheung Kong Infrastructure consortium from the sale of ETSA Power were $150 million, implying that its payment (inclusive of the unfunded superannuation liability) for the distribution business on a stand-alone basis was $3,344 million. This figure is used as the estimate of the market value of the 200 year leasehold interest in ETSA Utilities.

Derivation of the regulatory values, and regulatory regime

The Government prescribed the regulatory value of the ETSA Utilities' system-assets prior to the sale of the 200 year lease in the entity,[114] and a projected rolled-forward value was provided approximately the time of the sale. The Government also determined a price path for the network charges to apply until the first price review (which was to have effect after June 2005).

The assets for which values were specified excluded non-system assets. The non-system assets were assumed to amount to 5 per cent of the total regulatory asset base, based upon experience elsewhere.

Results

The figures discussed above imply the following ratio of the market-to-regulatory value.

Business	Estimated RAV	MV / RAV
ETSA Utilities	**2,263**	**1.5**

[112] Cheung Kong Infrastructure, 'AGL Rejoins CKI and HK in ETSA Businesses', Media Release, 14 January 2000; AGL, 'AGL Adds 734,000 Electricity Customers in South Australia, Media Release, 14 January 2000.

[113] Cheung Kong Infrastructure, 'AGL Rejoins CKI and HK in ETSA Businesses', Media Release, 14 January 2000.

[114] *Electricity Pricing Order*, issued by the Treasurer pursuant to section 35B of the Electricity Act 1996 (SA), 11 October 1999.

West Australian Gas Distribution Privatisation

Principal Activities of the Business

The AlintaGas Limited Group's core operating businesses comprised a distribution business (AlintaGas Networks) and a gas trading and retail business (AlintaGas Sales).[115]

The AlintaGas' distribution systems consisted of four discrete systems:

- Mid-West and South-West Gas Distribution Systems (natural gas);
- Kalgoorlie-Boulder Gas Distribution System (natural gas);
- Albany Gas Distribution System (LPG); and
- The Vines Gas Distribution System (LPG), in the Swan Valley, north east of Perth.

The total system comprised approximately 10,500 km of pipelines, and supplies about 420,000 customers (about 98 per cent of whom are residential).

The Mid-West and South-West Gas Distribution Systems were covered under the *National Third Party Access Code for Natural Gas Pipeline Systems*. The other gas distribution systems were not subject to regulation under the Code; however, these systems accounted for less than 1 per cent of AlintaGas' residential customers.

AlintaGas also had a contract to supply LPG (propane and butane) to Wesfarmers LPG, which is commingled with the natural gas in the Epic Energy owned Dampier to Bunbury Natural Gas Pipeline, and removed at the Wesfarmers LPG plant at Kwinana. The price for the LPG comprises two components: a base price and an incremental price, with the latter depending upon the world LPG price. This agreement continues in force until 30 June 2005 and thereafter until terminated by at least one year's notice by either party.

Purchaser and Sale Proceeds

The Government decided to list AlintaGas on the Australian stock exchange, rather than to proceed with a trade sale. However, it also decided to sell a significant portion of the equity (45 per cent) to a 'cornerstone' investor, prior to offering the remainder to retail and institutional investors.

The 'cornerstone shareholding' was sold to a consortium comprised of United Energy (50%) and Utilicorp (50%), and was announced on 31 July 2000.[116] The remaining shares where then sold through an Initial Public Offering, which closed on 29 September 2000 for the retail offer and 9 October 2000 for the institutional offer. The shares in AlintaGas commenced trading on 17 October 2000.

[115] The information on AlintaGas' principal activities is taken from the AlintaGas public offer document: AlintaGas Limited, 2000, Public Offer Document. AlintaGas had also set up a subsidiary company, AlintaGas Finance, to organise and provide finance to the other group companies. However, this function is required in any infrastructure company.

[116] United Energy, 'Utilicorp and United Energy Win Bid for AlintaGas', ASX Releases, 31 July 2000.

The price realised for the cornerstone shareholding was approximately $4.36 per share (excluding stamp duty). The shares to retail investors (42.9 per cent) were sold for $2.25 per share, and the portion to institutional investors (12.1 per cent) were sold for $2.45 per share.[117]

The Government's gross proceeds from the sale were as follows:[118]

[117] AlintaGas Sale Steering Committee, November 2000. Report on the Sale of the Businesses of the Gas Corporation, pp 20,26.

[118] AlintaGas Sale Steering Committee, November 2000. Report on the Sale of the Businesses of the Gas Corporation, p 32.

	$m
Debt[119]	450
Cornerstone Shareholding (45%)	319.5
Initial Public Offering (55%)	201.5
Total	**971.0**

The other implied values are approximately:

- $1,148 million using the price paid for the cornerstone shareholding;
- $810 million using the price set by Government for the retail investors; and
- $842 million using the price set by Government for the institutional investors.

The proceeds received by Government are used in the calculations below.

Information on the Spread of Bids

No information has been found on the spread of the bids for the cornerstone shareholding. Since listing, the shares have fluctuated between $2.72 and $3.98.

Value of any other businesses

The most important of the other activities of AlintaGas was the retailing of natural gas. The implied value of AlintaGas' regulated activities is demonstrated for a range of benchmarks for the value of its retail business (in $/customer terms), as discussed above.

As stated above, AlintaGas also sells LPG to Wesfarmers, and has a risk sharing arrangement whereby it bears part of the loss when the world LPG price is low, but shares in the gains when the world price is high. The commercial terms of this agreement (including the revenue received under the contract by AlintaGas) are confidential, but it is known that the favourable LPG prices have made a significant contribution to its first year results. The following open briefing provided after the release of the first year results sheds some light on the value of the contract:[120]

> **corporatefile.com.au**
>
> AlintaGas Limited today reported a net profit after tax of $42.2 million for the year to June 30, 2001, which was 62 percent above the forecast in your prospectus of $26.1 million. What were the main reasons for the outperformance?
>
> **CEO Bob Browning**
>
> All parts of our business contributed to AlintaGas's performance over the past year, both in terms of revenue and reducing our operating costs.
>
> The Wesfarmers LPG contract was a standout contributor because of high world LPG prices but our core gas sales market was surprisingly strong. We achieved 4.6 percent customer growth against a backdrop of lower housing starts. That exceeded our expectations and helped our penetration into the retail market.
>
> …

[119] AlintaGas, Public Offer Document, 18 August 2000, page 49.

[120] AlintaGas, CEO Browning on Profit and Growth, Open Briefing, 31 July 2001.

corporatefile.com.au

AlintaGas's operating revenue and EBIT for the year were $389.8 million and $121.8 million respectively. What did your entitlement to LPG sales from Wesfarmers' Kwinana LPG plant contribute to these numbers?

CEO Bob Browning

We can't disclose that for commercial reasons but our Public Offer Document (POD) forecast the EBITDA contribution from the AlintaGas Sales business unit, including our share of the LPG contract, to be $38 million for the year to June 30, 2001. The actual EBITDA for AlintaGas Sales was $65.2 million and the LPG contract was certainly a contributor to that result.

However, there is insufficient information available from which to estimate the value of the contract (rather than the change from prospectus forecasts). The market value figures below are therefore not adjusted to remove an assumed value for the LPG contract.

Derivation of the regulatory values, and regulatory regime

The starting regulatory value for AlintaGas (and its initial reference tariffs) were determined by the Independent Gas Pipelines Access Regulator Western Australia prior to the sale of the assets.[121] The updated regulatory value for AlintaGas was derived from the information in that decision.

The public information on the sale did not disclose the date at which the transaction was financially effective, and so the regulatory value as at 31 December 2000 (the quarter in which AlintaGas was listed) has been used.

Results

The following ratios of market-to-regulatory values are derived for the range of retail business value benchmarks.

Business	**Estimated RAV**	**MV / RAV**			
		Retail = $200/cust	***Retail = $600/cust***	***Retail = $1000/cust***	***Retail = $946/cust***
AlintaGas	585	1.5	1.2	0.9	1.0

When interpreting these results, the following should be noted.

- The value to AlintaGas of the LPG contract has not been excluded (explicitly) from the value of the entity.

It may be expected that the value of a retail business in WA would be far lower than in the east because:

- it is subject to tight price controls, cannot pass-through changes in transmission prices, and there was uncertainty about future transmission prices;
- bidders may have discounted the likelihood that there will be full retail contestability in electricity (a natural synergy for a gas retailer) on terms that would allow a serious challenge Western Power's monopoly; and

[121] Office of Gas Access Regulation, Final Decision: Access Arrangement, Mid-West and South-West Gas Distribution Systems, 30 June 2000

- average gas consumption by residential customers is very low (about 19 GJ/annum compared to 55 GJ/annum in Victoria).

A.4 Private Trade Sales

CitiPower – Sale by Entergy to AEP

Principal Activities

CitiPower's principal activities when it was privatised were described above. These were still its principal activities when this transaction took place. It retailed to about 243,000 customers at the time of this transaction.[122]

Purchaser and Sale Proceeds

Entergy sold the CitiPower business to American Electric Power (a US utility) for $1,700 million. The completion of the sale was announced on 31 December 1998.[123]

Information on the Spread of Bids

No information is available publicly as to whether there were any other bidders or on the spread of any such bids.

Value of any other businesses

As with the analysis of CitiPower at the time of privatisation, a range of values for the MV/RV ratio is provided, which reflect different benchmarks for the value of retail businesses (in $/customer terms), as discussed above.

Derivation of the regulatory values, and regulatory regime

The regulatory value was derived using the same approach as described for CitiPower above.

There was no announcement of the time at which the sale took financial effect; hence, the regulatory asset value as at 31 December 1998 is used (the date which the completion of the sale was announced).

It is noted that the transaction took place after the Office of the Regulator-General had released its Final Decision on its review of the Access Arrangements for the three principal gas distributors (Multinet, Westar and Stratus).

Results

The following ratios of market-to-regulatory values are derived for the range of retail business value benchmarks.

Business	Estimated RAV	MV / RAV

[122] CitiPower, 'AEP Resources Completes Acquisition of CitiPower; Announces New CEO and Board', Media Release, 31 December 1998.

[123] CitiPower, 'AEP Resources Completes Acquisition of CitiPower; Announces New CEO and Board', Media Release, 31 December 1998.

		Retail = $200/cust	***Retail = $600/cust***	***Retail = $1000/cust***	***Retail = $609/cust***
CitiPower	702	2.4	2.2	2.1	2.2

Powercor – Sale by ScottishPower to CKI/HEH

Principal Activities

Powercor's principal activities when it was privatised were described above. These were still its activities when this transaction took place.

Purchaser and Sale Proceeds

ScottishPower[124] sold Powercor to a consortium comprising Cheung Kong Infrastructure and Hong Kong Electric for $2,315 million.[125] The sale was announced on 3 August 2000, and expected to be completed before 15 September 2000.

Information on the Spread of Bids

No information is available publicly as to whether there were any other bidders or on the spread of any such bids.

Value of any other businesses

Cheung Kong Infrastructure and Hong Kong Electric announced on 16 April 2001 the agreement to sell the retail business, together with all energy market positions, to Origin Energy, which was expected to be completed around 1 June 2001.[126] The sale price for the retail business was $315 million (which is equivalent to $308 million at the time of Cheung Kong Infrastructure and Hong Kong Electric's purchase of Powercor, after adjusting for inflation).

Origin also entered into a service agreement for Powercor to provide certain services over the first year. These services, which included billing and call centre services, and the development of new systems, were expected to lead to an additional payment of about $55 million by Origin. However, the provision of these services would only increase the value of the transaction to Cheung Kong Infrastructure and Hong Kong Electric by the amount of any margin earned above costs incurred in providing these services. The potential margin earned on $55 million is unlikely to be significant, and so has been ignored in the analysis.

Derivation of the regulatory values, and regulatory regime

The regulatory value was derived using the same approach as described for Powercor above.

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124 ScottishPower became the owner of Powercor through a merger of Powercor's parent company, PacifiCorp and ScottishPower: Powercor, 'Powercor Joins ScottishPower Group', Media Release, 1 December 1999.

125 Cheung Kong Infrastructure, 'Further Powering into Australia – CKI and Hong Kong Electric Spend over HK$10b to Acquire Powercor', Media Release, 3 August 2000.

126 Cheung Kong Infrastructure, CKI and Hong Kong Electric Dispose of Australian Powercor Retail Business', Media Release, 16 April 2001.

There was no statement about the date at which the sale would take financial effect, and so the regulatory value as at 30 September 2000 (the date that is closest to the completion date for the sale) is used.[127]

It is noted that the transaction took place after the Office of the Regulator-General had released its Draft Decision for the 2001 review of the price controls for the electricity distributors.

Results

The following ratio of the market-to-regulatory value is implied by the figures discussed above.

Business	Estimated RAV	MV / RAV
Powercor	**1,428**	**1.4**

Citipower – Sale by AEP to CKI/HEH

Principal Activities

CitiPower's principal activities when it was privatised were described above. These were still its principal activities when this transaction took place, at which time it retailed to about 264,000 customers.

Purchaser and Sale Proceeds

AEP sold Citipower to a consortium comprising Cheung Kong Infrastructure and Hong Kong Electric Holdings for $1,555 million. The sale was announced on 22 July 2002[128], and was to be completed by 1 September 2002.

Information on the Spread of Bids

No information is available publicly as to whether there were any other bidders or on the spread of any such bids.

Value of any other businesses

Cheung Kong Infrastructure and Hong Kong Electric Holdings announced, concurrent with the purchase of Citipower, an agreement to sell the retail business to Origin Energy.[129] The sale price for the retail business was $137 million.

Derivation of the regulatory values, and regulatory regime

The regulatory value was derived using the same approach as described for CitiPower above.

There was no statement about the date at which the sale would take financial effect, and so the regulatory value as at 30 September 2002 (the closest quarter to the completion date for the sale) is used.[130]

[127] The regulatory value is derived from Office of the Regulator General, Victoria, Electricity Distribution Price Determination 2001-2005, Volume 1, September 2000

[128] Joint Press Release, Cheung Kong Infrastructure and Hong Kong Electric Holdings, 22 July 2002

[129] Joint Press Release, Cheung Kong Infrastructure and Hong Kong Electric Holdings, 22 July 2002

Results

The following ratio of the market-to-regulatory value is implied by the figures discussed above.

Business	Estimated RAV	MV / RAV
CitiPower	**894**	**1.6**

A.5 Market Values Implied by the Share Price of Listed Entities

Envestra

Principal Activities

Envestra is the owner of the following gas distribution systems:

- The South Australian gas distribution system (formerly SAGASCO), which services the Adelaide (including the Barossa Valley), Peterborough, Port Pirie, Riverland, South East and Whyalla regions. As at 30 June 1998, it consisted of about 6,800 km of mains, and served about 330,000 customers.[131]

- One of the principal Queensland gas distributors (formerly the Gas Corporation of Queensland), which supplies gas to areas of Brisbane (including Ipswich and suburbs north of the Brisbane river), and Rockhampton and Gladstone. The network comprises about 2,070 km of mains, and serves about 71,200 customers.[132]

- One of the principal gas distributors in Victoria (formerly Stratus Networks), which has already been described above.

- The gas reticulation system in Alice Springs (formerly Centre Gas Pty Ltd); and

- The recently constructed gas distribution system in Mildura. Envestra (in a consortium with Boral) won a competitive tender run by the Mildura Rural City Council to distribute and retail gas to Mildura in November 1997.[133]

Envestra also owns the following transmission pipelines:

- the Riverland pipeline in South Australia, which is a 235.6 km pipeline from Angaston and Berri (both in South Australia);[134]

130 The regulatory value is derived from Office of the Regulator General, Victoria, Electricity Distribution Price Determination 2001-2005, Volume 1, September 2000

131 South Australian Independent Pricing and Access Regulator, Access Arrangement for the South Australian Distribution Systems, Draft Decision, 13 April 2000, page 23.

132 Queensland Competition Authority, Final Decision, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited, October 2001, page 40.

133 Office of the Regulator-General, Access Arrangement for Envestra Limited in Respect of the Proposed Mildura Natural Gas Distribution System, Final Decision, 3 June 1999, page 4.

134 Envestra, Access Arrangement Information for the Riverland Pipeline, Undated, pages 1 and 46.

- the Mildura pipeline, which is a 147.7 km extension to the Riverland pipeline, running from near Berri to Mildura in Victoria;[135] and
- the 140 km pipeline connecting the Palm Valley gas field in the Northern Territory to Alice Springs.[136]

The portion of Envestra's total revenue that is earned from the first three of the assets is about 40 per cent, 13 per cent and 45 per cent, respectively (or 98 per cent in total).[137]

In all cases, Envestra sells haulage services to gas retailers – Envestra does not retail gas. Envestra has also contracted out the operations and maintenance of its systems to Origin Energy (Origin Energy Asset Management, or OEAM). OEAM's obligations include, amongst other things, to manage the haulage of gas, to maintain the network, to plan design and construct network extensions.[138] OEAM is paid for all of its costs and reimbursements reasonably incurred in the performance of its obligations, plus a management fee that currently is set at 3 per cent of network revenue. OEAM and Envestra settle budgets prior to the commencement of each year, and OEAM may also receive incentive bonuses related to the cost of connecting customers, and controllable operating expenditure.[139]

Estimate of the Market Value of the Assets

Estimates of the market values of Envestra's assets have been derived as described in section A.2.

Value of any other businesses

Envestra's only principal activity is investing in gas transportation infrastructure (ie transmission and distribution).

Derivation of the regulatory values, and regulatory regime

In deriving Envestra's regulatory values, the following matters and assumptions need to be noted.

- Regulatory values were determined in October 1998 for its Victorian assets and for the Albury Gas Company, and these have been updated as discussed already. The regulatory values for its Queensland distribution assets were determined in October 2001,[140] and for its South Australian assets in December 2001.
  - Estimates have been made of the regulatory value of Envestra's SA assets prior to December 2001 final decisions using information from the relevant

135 Envestra, Access Arrangement Information for the Mildura Pipeline, 11 November 1999, pages 42-43.

136 Envestra, Access Arrangement Information for the Mildura Pipeline, 11 November 1999, page 1.

137 Envestra, 2000-2001 Annual Report, page 7.

138 OEAM has sub-contracted the day to day physical operation of the Riverland pipeline to the operator of the Moomba-Adelaide pipeline, Epic Energy.

139 Envestra, 'Operating Agreements' (www.envestra.com.au/operations/page0018.asp); Envestra, Prospectus, 21 July 1997, pages 116-120.

140 Queensland Competition Authority, Final Decision, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited, October 2001. Information from this decision was used to obtain an estimate of the regulatory asset base from the start of the period.

Draft Decision and Envestra's proposal (as necessary).[141] However, given the lack of detail in the Draft Decision for Envestra's South Australian assets, we would caution against placing significant weight on the results prior to December 2001. The regulatory values for the period after the release of the final decisions has been derived from the final decisions.[142]

- Coverage of the Riverland and Mildura pipelines under the Code has been revoked, although Envestra had already submitted proposed Access Arrangements for both of these pipelines. For the purpose of this analysis, it has been assumed that these assets continued to be covered, with the regulatory asset value of that proposed by Envestra.
- The Mildura pipeline is also no longer covered by the Code and no regulatory value was ever established. The Northern Territory assets also are not covered under the Code, and there is no information from which to estimate proxy regulatory values or market values. Lastly, it is known that the value associated with several user-specific facilities have been omitted from the regulatory values used in this report.
  - For the purpose of this analysis, this last category of assets has been ignored. However, it would be expected that these assets would not make up any more than a trivial share of either Envestra's market value or regulatory value (if all were regulated). Hence, their exclusion would not be expected to change the conclusions.

Results

The following ratio of the market-to-regulatory value is implied by the figures discussed above.

Business	Date	Market Value of Assets	Estimated RAV	MV / RAV
Envestra	30/6/2001	2,259	1,683	1.3
	31/12/2001	2,352	1,644	1.4
	30/6/2002	2,273	1,678	1.4
	31/12/2002	2,443	1,710	1.4

141 South Australian Independent Pricing and Access Regulator, Draft Decision – Access Arrangement for the South Australian Distribution Systems, 13 April 2000; Envestra, Revised Access Arrangement Information for the South Australian Distribution System, 21 July 1999;

142 South Australian Independent Pricing and Access Regulator, Final Decision – Access Arrangement for the South Australian Distribution Systems, December 2001; Queensland Competition Authority, Final Decision, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited, December 2001.

AlintaGas

Principal Activities

AlintaGas' principal activities were discussed above, and are unchanged since the privatisation of the asset. AlintaGas has contracted out some activities to United Energy for a fee (including the secondment of employees, a strategic review of AlintaGas, training of AlintaGas personnel; and any other services necessary for AlintaGas to achieve its objectives and business plan).[143]

Estimate of the Market Value of the Assets

Estimates of the market values of Envestra's assets have been derived as outlined in section A.2.

Value of any other businesses

The most important of the other activities of AlintaGas is the retailing of natural gas. The implied value of AlintaGas's regulated activities is demonstrated for a range of benchmarks for the value of its retail business (in $/customer terms). The derivation of the benchmarks for retail business values is discussed in section 4 below.

As noted above, AlintaGas also has a LPG contract with Wesfarmers with a risk sharing arrangement based upon the world LPG price, which currently is very favourable to AlintaGas. The value of this contract has not been removed from the value of the regulated entity

Derivation of the regulatory values, and regulatory regime

The derivation of the regulatory asset base for AlintaGas was discussed above.

Results

The following ratios of the market-to-regulatory value are implied by the figures discussed above.

Business	**Date**	**Market Value of Assets**	**Estimated RAV**	**MV / RAV**			
				Retail = $200/cust	***Retail = $600/cust***	***Retail = $1000/cust***	***Retail = $946 to $970/cust***
AlintaGas	30/6/2001	967	601	1.5	1.2	0.9	0.9
	31/12/2001	941	609	1.4	1.1	0.8	0.8
	30/6/2002	1058	618	1.6	1.3	1.0	1.0
	31/12/2002	1016	626	1.5	1.2	0.9	0.9

[143] United Energy, United Energy's Operating Services Agreement with AlintaGas Activated, Media Release, 2 March 2001.

GasNet

Principal Activities

GasNet succeeded Transmission Pipelines Australia, the activities of which are discussed above.

Estimate of the Market Value of the Assets

Estimates of the market values of GasNet's assets have been derived as outlined in section A.2.

Estimate of the Market Value of Other Businesses

As noted above, GasNet had a half share in the LNG facility at Dandenong at the time of the privatisation, which it has retained. This was estimated by an equity analyst to have a market value of $60 million in March 2003, which has been adjusted for inflation to provide an estimate of the market value of this activity at the time of privatisation.

Derivation of the regulatory values, and regulatory regime

The derivation of the regulatory value for GasNet's assets was discussed above.

Results

The following ratios of the market-to-regulatory value are implied by the figures discussed above.

Business	Date	Market Value of Assets	Estimated RAV	MV / RAV
GasNet	31/12/2001	772	497	1.6
	30/6/2002	749	495	1.5
	31/12/2002	799	494	1.6