1 Introduction

On 13 June 2003, the Treasurer asked the Productivity Commission to undertake an inquiry into the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) and to report within twelve months.

1.1 Background to this inquiry

The Council of Australian Governments agreed, in February 1994, to general principles of competition policy reform to enable third parties, in particular circumstances, to gain access to essential facilities. The Gas Access Regime is an industry-specific regime under the umbrella of the national access regime (part IIIA of the *Trade Practices Act 1974*).

The Australian, State and Territory governments have implemented a National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), which is given legal effect in each jurisdiction through a Gas Pipelines Access Law (contained within a Gas Pipelines Access Act). The Gas Code is incorporated into the relevant legislation as schedule 2. There is scope for each State and Territory to have different institutional arrangements, such as regulatory and appeal bodies.

The Gas Access Regime applies to all pipelines that are deemed to be 'covered'. Coverage decisions are made by the relevant Minister following a recommendation from the National Competition Council. Once a pipeline is covered under the regime, a service provider is required to put in place an access arrangement approved by the relevant regulator (the Australian Competition and Consumer Commission or relevant State or Territory regulator). Guidelines for access arrangements are set out in the Gas Code, such as the conditions under which access will be offered (including prices), policies relevant to the operation and extension of a pipeline, and a review date.

A service provider and access seeker are free to agree on terms and conditions that differ from those in the access arrangement. However, if an access dispute arises, arbitration will result in the arbitrator imposing the default terms and conditions set out in the access arrangement. There are mechanisms for appealing decisions, including those on coverage, access arrangements and disputes over access.

1.2 Scope of the inquiry

The Commission has been asked to review the Gas Access Regime with the primary aim of examining the extent to which the regime balances the interests of relevant parties, provides a framework that enables efficient investment in new pipelines and network infrastructure, and facilitates the development of competition in the natural gas market. In particular, the terms of reference for the inquiry ask the Commission to:

- analyse the benefits, costs and effects of the regime, particularly on investment and competition
- consider ways to improve the regime
- identify and investigate the appropriateness of including in the Gas Code minimum price and non price requirements.

The Commission's review is being undertaken within the framework of the national access regime (part IIIA of the Trade Practices Act), clause 6 of the Competition Principles Agreement 1995, and the National Energy Policy Framework agreed to by the Council of Australian Governments in June 2001. The Commission is also required to take into consideration the Australian Government's response (Costello 2004) to the Productivity Commission's review of the national access regime (PC 2001c) and outcomes arising from the Council of Australian Governments Energy Market Review (EMR 2002).

In addition, the Commission also must have regard to the general policy guidelines set out in the *Productivity Commission Act 1998.*

The Commission has sought to explicitly guide the actual implementation of its higher-level policy recommendations. To this end, the Commission has made a number of detailed and technical recommendations, with proposals for specific changes to the Gas Code.

1.3 Conduct of the inquiry

In line with the usual operating procedures and guidelines for inquiries, the Commission has sought to conduct the inquiry in an open and transparent manner.

Upon receipt of the terms of reference in June 2003, the Commission placed advertisements announcing the inquiry in several national newspapers and issued a circular to parties with a potential interest in the inquiry.

The Commission also held informal discussions in Adelaide, Brisbane, Canberra, Melbourne, Perth and Sydney with various interested parties, including pipeline owners and operators, gas users, industry associations, regulators and other government agencies.

In July 2003, the Commission released an issues paper which, apart from calling for submissions, sought to provide guidance to participants on the range of issues within the scope of the inquiry and advice on how to go about preparing submissions.

A total of 76 submissions were received in response to the issues paper, from a variety of groups within, and related to, the gas industry. These groups included pipeline owners and operators, gas users, industry associations, regulators and other government agencies. These submissions were placed on the Commission's website and copies were placed on public display at the Commission's offices in Melbourne and Canberra. In September 2003, the Commission held public hearings in Perth, Adelaide, Melbourne, Brisbane and Sydney.

The Commission released its draft report for public comment on 15 December 2003. Fifty submissions were received in response to the draft report. Twenty-six participants made presentations at the second round of public hearings held in Melbourne, Brisbane, Sydney, Adelaide and Perth in March and April 2004. The Commission thanks participants for their participation in meetings with the Commissioners and Commission staff, their participation in first and second round public hearings and for their submissions in response to the issues paper and draft report. Appendix A provides details of the individuals and organisations that participated in the inquiry through submissions, visits and/or appearance at public hearings.

1.4 Structure of the report

The Australian gas industry is examined in the next chapter. The Gas Access Regime, including its history, is outlined in chapter 3. Whether the Gas Access Regime is working is discussed in chapter 4.

Improvements to the Gas Access Regime are considered in the remaining chapters. Improving the specification of the regime's objectives is discussed in chapter 5. Improvements to the coverage criteria and coverage process are outlined in chapter 6. Improvements to the current approach to regulation (access arrangements with reference tariffs) are discussed in chapter 7. A light-handed (monitoring) alternative is discussed in chapter 8. Options to minimise the adverse effect of regulation on investment are examined in chapter 9. Improvements to ring fencing and associate contracts provisions, administrative and appeal processes, and institutional arrangements are examined in chapters 10, 11 and 12, respectively.

2 Australian gas industry

Like many industries, the natural gas industry comprises distinct sectors within the supply chain. The four main sectors are (1) exploration and production, (2) transmission, (3) distribution, and (4) retailing (figure 2.1). These sectors take the natural gas from the point of extraction — the well head — to the point of consumption — the burner tip. Each sector is discussed in this chapter, along with the market characteristics of the transportation of natural gas from gas fields to the city gate or large users (transmission) and then the reticulation of the gas to other end users (distribution).

2.1 Gas supply chain

Exploration and production

Australia has abundant reserves of natural gas. In January 2001, recoverable reserves were estimated to be 158 534 petajoules (table 2.1) — equivalent to about 130 years supply at current production levels. About 20 per cent of this amount is currently commercial[1].

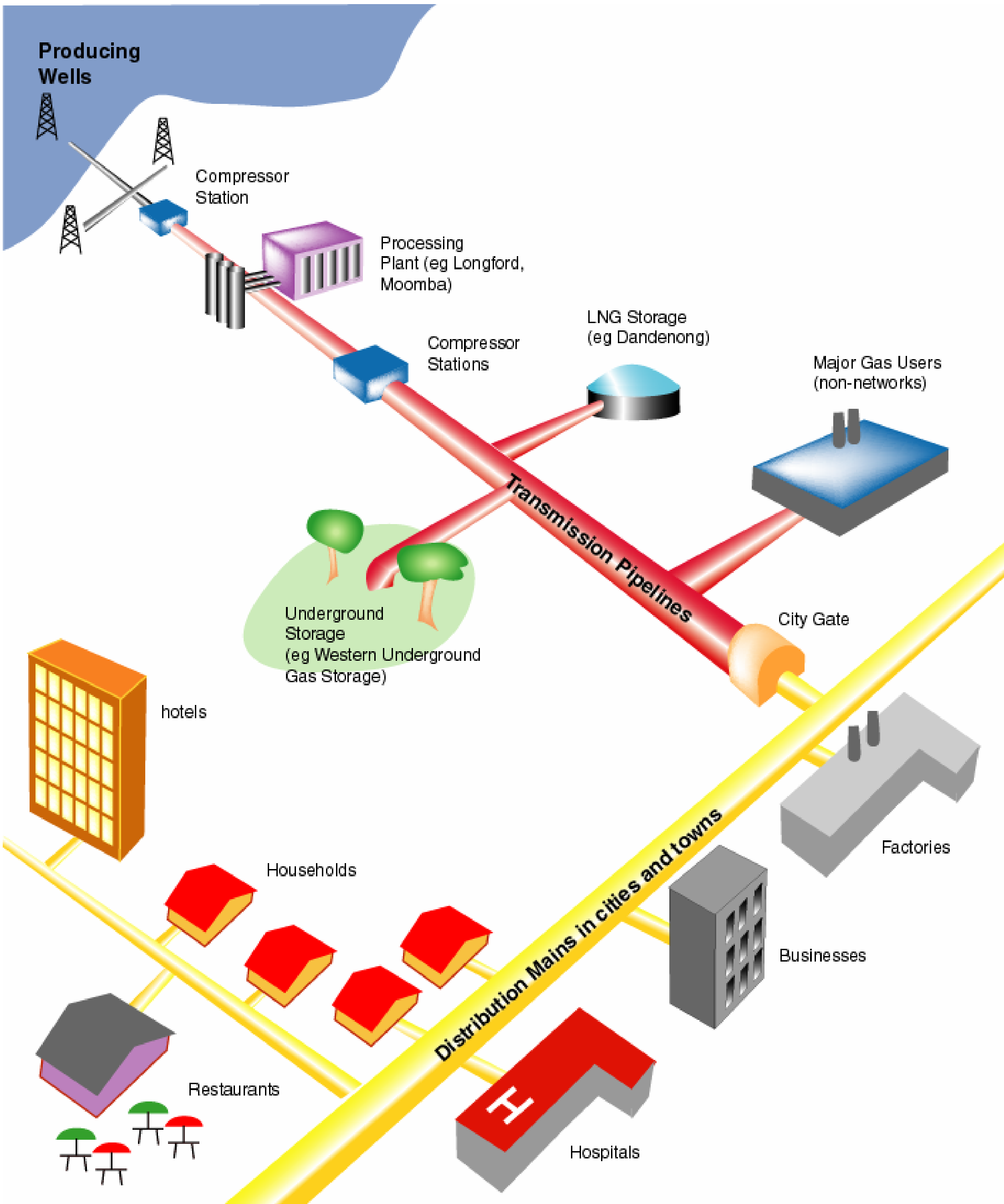
Most of the major gas reserves are offshore and some distance from the major markets (figure 2.2). The gas basins with the largest recoverable reserves are the Carnarvon and Browse basins in Western Australia, the Bonaparte Basin in the Northern Territory, the Gippsland Basin in Victoria and the Cooper–Eromanga Basin that straddles South Australia and Queensland. Although the Bonaparte and Browse basins have significant reserves, they are yet to be developed (table 2.1).

The exploration and production of natural gas in Australia is undertaken by many companies, including BHP Billiton, BP, Chevron Texaco, ExxonMobil, OMV, Origin Energy, Santos, Shell, Woodside Energy and a growing number of smaller exploration companies. Joint venture consortia undertake almost all natural gas exploration in Australia, primarily as a mechanism for risk and cost sharing.

[1] Commercial reserves are proven reserves that can be supplied to markets on a profitable basis, based on the current costs of production and the prevailing price of gas (Dickson and Noble 2003).

Whenever these gas reserves are subsequently exploited, these consortia tend to undertake joint production and marketing (EMR 2002). There is some cross-ownership within and across natural gas basins. Santos, for example, has interests in all of the fields in the Cooper–Eromanga Basin and ExxonMobil has interests in both the Cooper–Eromanga and Gippsland basins.

Figure 2.1 **Gas supply chain**



Source: Australian Gas Association, pers. comm., 18 July 2003.

Natural gas is extracted from underground wells and then processed into pipeline quality gas for domestic markets or liquefied natural gas (LNG) for export.

The total production of natural gas in Australia in 2001 was 1233 petajoules, with around 30 per cent exported as LNG and the remainder used in the domestic market. Of total production, 95 per cent came from three basins: Carnarvon (58 per cent), Gippsland (19 per cent) and Cooper–Eromanga (17 per cent). The ratio of recoverable reserves to production differs significantly across these basins, with Cooper–Eromanga having the smallest ratio.

Australia also has coal seam methane reserves[2] in Queensland, New South Wales and Victoria, which are beginning to be developed. However, large scale recovery has not yet been demonstrated to be commercially viable (APIA 2003). An estimated 20 petajoules of coal seam methane is currently produced each year (Dickson, Fainstein and Harman 2002).

Table 2.1 **Natural gas basins, 2001**

Basin	*Jurisdictions supplied*	*Recoverable reserves*	*Commercial reserves*[a]	*Production*	*Reserves to production ratio*[b]
		PJ	%	PJ/year	years
Carnarvon	WA	81 679	29	720	113
Browse	..	33 671	**na**	–	..
Bonaparte	..	27 077	–	–	..
Gippsland	Vic, NSW	8 029	74	239	34
Cooper–Eromanga	SA, Qld, NSW, Vic	4 416	79	211	21
Otway	Vic	1 700	2	8	213
Perth	WA	985	10	11	90
Bass	..	376	**na**	–	..
Amadeus	NT	358	94	19	19
Bowen–Surat	Qld	229	47	24	10
Adavale	**na**	14	100	1	14
Total	**na**	**158 534**	**21**[c]	**1 233**	**129**

[a] Proportion of recoverable reserves that are commercial — that is, the proportion that can be supplied on a profitable basis, based on current costs and prices. [b] Productivity Commission estimates of recoverable reserves divided by annual production. [c] Productivity Commission estimate of total commercial reserves divided by total recoverable reserves, expressed as a percentage. **na** Not available. **..** Not applicable. **–** Nil or rounded to zero.

Sources: AGA 2003; Dickson and Noble 2003; PC estimates.

[2] Preliminary estimates of recoverable reserves of coal seam methane are between 20 418 and 44 418 petajoules (AGA 2003).

Figure 2.2 **Australian gas basins**

Source: Australian Gas Association, pers. comm., 21 November 2003.

Transmission

Transmission pipelines generally transport large volumes of natural gas under high pressure from production fields to the city gate, or to large customers along the pipeline. The capacity of a transmission pipeline — the quantity of gas that can be transported in a given time period — is primarily related to its diameter, its length and the difference in pressure between the two ends of the pipe. The larger the pressure differential, the faster gas will flow (Stewart, Meroney and O'Neil 1995). Compressor stations are used to increase the capacity of a pipeline. Compressors increase capacity by raising the pressure (at the high pressure end) and effectively maintaining that pressure along the length of the pipeline. New pipelines are generally constructed with a compressor at their head.[3] As demand grows, the service provider can add extra compressors.

A service provider can also increase capacity through looping — that is, duplicating sections of the pipeline. Looping increases a pipeline's capacity because the pressure does not drop as quickly in the looped section, which leads to a greater pressure differential and a faster gas flow in the unlooped portion (Stewart, Meroney and O'Neil 1995).

Transmission pipelines transport gas from gas fields to major demand centres (figure 2.3). There were over 20 000 kilometres of transmission pipeline in 2002, having risen by 43 per cent (from just over 14 000 kilometres) since 1997. In the five-year period before 1997, there was a 35 per cent increase in the kilometres of pipeline (Australian Gas Association, pers. comm., 11 November 2003). Several pipelines are under construction, including Enertrade's Moranbah–Townsville pipeline and GasNet Australia's Port Hedland–Telfer pipeline.

The specific characteristics (length, throughput, diameter, owners and operators) of the current major transmission pipelines vary (table 2.2). Major transmission pipeline owners include Australian Pipeline Trust (APT), CMS Gas Transmission Australia, Alinta, Epic Energy, GasNet Australia and Hastings Funds Management. There are no cross-ownership links between these pipeline owners. However, the APT is linked with the Australian Gas Light Company (AGL), which owns distribution networks in New South Wales. (AGL owns 30 per cent of the APT.) Some pipeline owners contract the operation of a pipeline to a system operator or asset manager. These contracts are often with associated companies (table 2.2).

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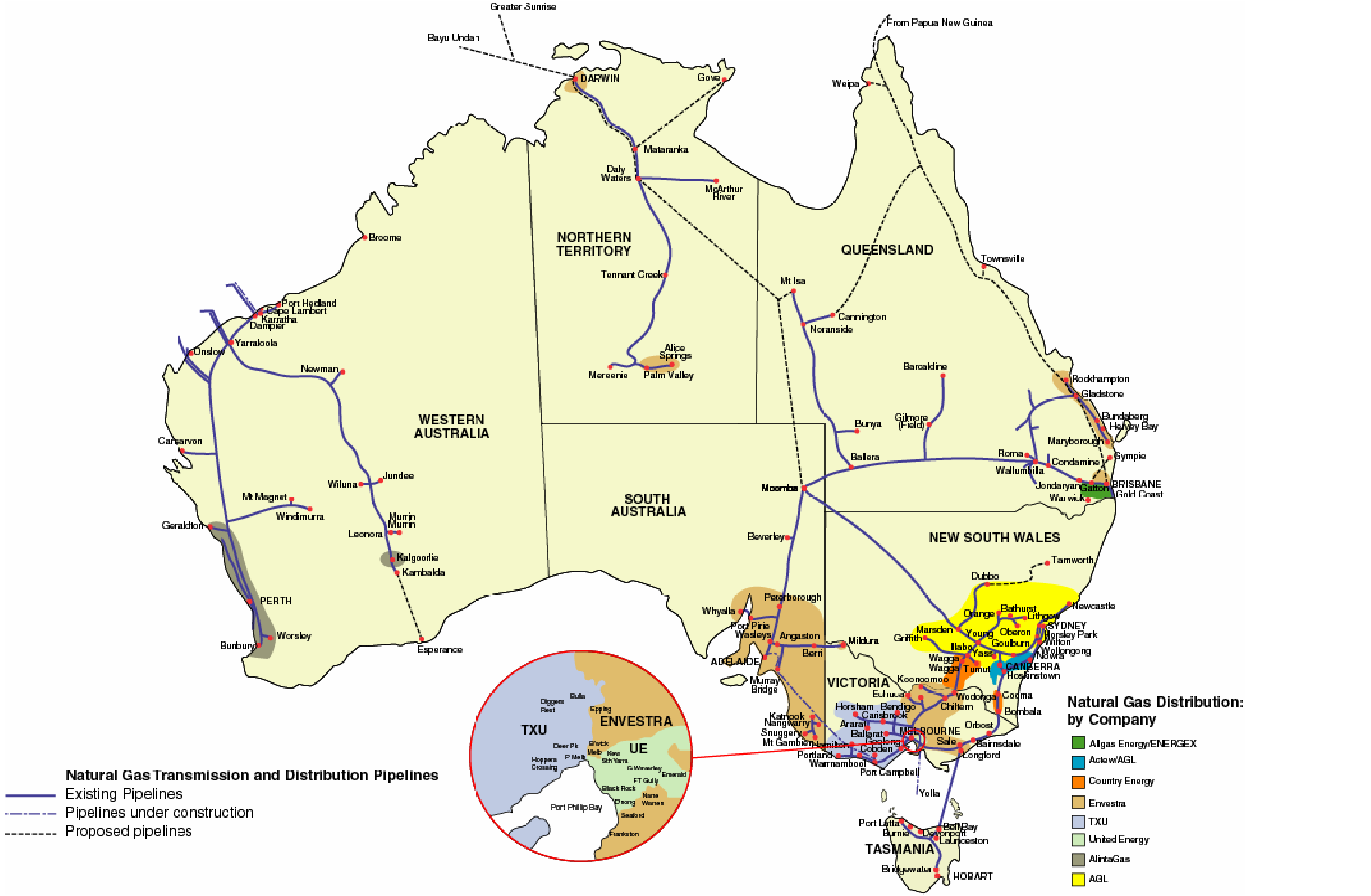
[3] A compressor is not required at the head of a pipeline if there is sufficient pressure from the gas flowing from a processing plant.

Figure 2.3 **Natural gas transmission and distribution activities**



Source: AGA 2003.

Table 2.2 **Current major transmission pipelines**

June 2004

Route	*Length*	*Throughput*[a]	*Diameter*	*Owner*	*Operator*
	km	PJ/year	mm		
Moomba–Sydney	2 013	152	864	APT	East Australian Pipeline[b]
Longford–Sydney	795	**na**	457	Alinta	Alinta
Amadeus Basin–Darwin	1 656	15	114/356	NT Gas	NT Gas[b]
Roma (Wallumbilla)–Brisbane	440	28	273/406	APT	APT Petroleum Pipelines[b]
Roma (Wallumbilla)–Gladstone	532	27	324	Alinta	Alinta
Ballera–Wallumbilla	756	28	406	Hastings Funds Management	Epic Energy[c]
Ballera–Mt Isa	840	30	324	APT and SWQ Producers	Roverton[b]
Moomba–Adelaide	1 102	104	89/600	Hastings Funds Management	Epic Energy[c]
Port Campbell–Adelaide	680	**na**	450/700	Origin Energy, Australian National Power and TXU Australia	South East Australia Gas
Victorian transmission system	1 930	211	168/762	GasNet Australia	GasNet Australia[d]
Dongara–Perth/Pinjarra	445	10	114/356	CMS Gas Transmission Australia	CMS Gas Transmission
Dampier–Bunbury	1 845	221	150/660	Epic Energy[c]	Epic Energy Western Australia Transmission[c]
Yarraloola–Newman/Kalgoorlie	1 427	30	219/400	Unincorporated joint venture[e]	Goldfields Gas Transmission[b]
Longford–Bell Bay (Hobart)	576	**na**	203/356	Alinta	Alinta

a Throughput is approximate. **b** Agility (100 per cent owned by AGL) provides management and operational services to the operator, but is not the operator. **c** The references in this table to Epic Energy relate to various entities within the Epic Energy group of companies. **d** VENCorp (a Victorian Government owned entity) is the independent system operator for the Victorian gas transmission system, the manager and developer of the Victorian wholesale gas market and provides system planning services for gas in the Victorian market carriage system. **e** Two of the joint venturers are Southern Cross Pipelines Australia (holder of around 63 per cent) and Southern Cross Pipelines (NDL) Australia (holder of around 26 per cent). These two companies are owned by the APT (55 per cent) and CMS Gas Transmission of Australia (45 per cent). **na** Not available.

Sources: Appendix C; APIA, pers. comm., 10 November 2003; Alinta 2004; Epic Energy 2004b.

Storage

Natural gas can be stored in transmission pipelines, underground storage facilities such as depleted reservoirs, or LNG facilities. Storage facilities are used to supplement supply for short durations in high demand periods.

Distribution

Distribution networks transport natural gas from gate stations and reticulate it into residential houses, offices, hospitals, factories and other businesses. This gas is transported in smaller volumes and at lower pressures than along the transmission pipelines. There are three classes of distribution network pipelines: high, medium and low pressure. Low and medium pressure pipelines account for around 60–70 per cent of distribution networks:

> … the high and medium pressure pipelines are used to service areas of high demand and to provide the 'backbone' of the system (for example, taking gas between population concentrations within a distribution area). The low pressure pipes serve as the last link in the chain to the end consumer. (Australian Gas Association, pers. comm., 11 November 2003)

The diameter of pipe used in distribution networks is also smaller than that used in transmission. Most distribution pipes have a diameter of 4–10 centimetres (Australian Gas Association, pers. comm., 11 November 2003).

Gate stations link transmission pipelines and distribution networks. These stations measure the quantity of gas leaving the transmission pipeline and reduce the pressure of the gas entering the distribution network. Further drops in pressure occur at regulating stations along a distribution network. By law, gas must be odorised at a gate station (if not already odorised upstream) (AGA 2003).

The natural gas distribution sector reticulated around 450 petajoules of natural gas to around 3.4 million residential households and 105 000 commercial and industrial customers in 2002 (AGA 2003). The volume of gas used by most individual customers is measured using meters installed at the point at which the customer is connected to the distribution network.

The capacity of existing distribution networks can be expanded to extend the network to new customers or geographic areas, or to meet increased demand from existing customers. A distributor can, for example, replace existing pipelines with larger diameter piping or piping capable of operating at higher pressures (Australian Gas Association, sub. 13, pp. 9–10).

There were around 75 500 kilometres of distribution network in 2002, having risen by 12 per cent (from around 67 500 kilometres) since 1997. In the five-year period before 1997, there was a 14 per cent increase in the kilometres of network (Australian Gas Association, pers. comm., 11 November 2003).

Distribution networks reticulate all of Australia's mainland capital cities and some regional towns (figure 2.3). A new major distribution network is under construction in Tasmania. It will reticulate natural gas in Hobart and to some of the population centres on the northern coast of Tasmania.

Major distribution companies include AGL Gas Networks, Alinta Gas Networks, Allgas Energy/ENERGEX, Envestra, TXU Networks, Multinet Gas Network (a company part owned and managed by Alinta) and ActewAGL Distribution (table 2.3).

Table 2.3 **Major distribution networks, by State and Territory**

Owner	*Operator*	*Major service contracts*	*Associated energy retailer*
New South Wales			
AGL Gas Networks	AGL Gas Networks	Agility[a]	AGL Energy Sales and Marketing[b]
Victoria			
Envestra[c]	Origin Energy Asset Management	Origin Energy Asset Management	None
TXU Networks[d]	T^2[e]	Abigroup and others	TXU Retail[b]
Multinet Gas Network[f]	Alinta Network Services	Alinta Network Services and others	None
Queensland			
Allgas Energy[g]	ENERGEX	ENERGEX	ENERGEX Retail[b]
Envestra[c]	Origin Energy Asset Management	Origin Energy Asset Management	None
South Australia			
Envestra[c]	Origin Energy Asset Management	Origin Energy Asset Management	None
Western Australia			
Alinta Gas Networks[h]	Alinta Network Services	Alinta Network Services and others	Alinta Sales[b]
ACT			
ActewAGL Distribution	ActewAGL Distribution	Agility[a]	ActewAGL Retail[b]

[a] Agility undertakes asset management functions. It is a wholly owned subsidiary of AGL. [b] Distributor is fully ring fenced from associated retailer for regulatory purposes. [c] Origin Energy has an 18.6 per cent shareholding in Envestra. Origin Energy Asset Management is a wholly owned subsidiary of Origin Energy. [d] Singapore Power is currently in the process of purchasing TXU Australia. [e] Joint venture between Tenix and TXU Networks. [f] Owned by Diversified Utility and Energy Trusts (majority owner) and Alinta. [g] Allgas Energy is 100 per cent owned by ENERGEX. [h] Owned by Alinta (majority owner) and Diversified Utility and Energy Trusts.

Source: Australian Gas Association, pers. comm., 31 October 2003.

As with transmission, a number of network owners contract the operation of a pipeline to a system operator or asset manager. Network owners often enter these contracts with associated companies (table 2.3).

Retailers

Retailers sell natural gas to end user consumers, including residential households, hospitals and factories. They effectively aggregate all the purchases of many small users to form a sizable purchase from suppliers. In 2001-02, retailers sold around 450 petajoules of natural gas (around 45 per cent of all natural gas consumed).[4]

- Residential households comprised 97 per cent of retail customers in 2001-02, accounting for 32 per cent of total gas sold by retailers.
- Commercial and industrial customers comprised 3 per cent of retail customers, accounting for 68 per cent of total gas sold by retailers.

Retailers create a range of products by varying the terms on which they offer gas to consumers, such as the time of delivery and the interruptability of supply (Roberts and Harman 2002). To deliver these products, a retailer purchases the outputs of upstream participants, generally entering contracts with gas producers for the supply of gas and paying the transportation tariffs associated with transmission and distribution. Users may provide their own retail services, but generally only large users do this.

Since 1997, most States and Territories have moved towards implementing full retail contestability — that is, allowing any sized user to choose a gas retailer.[5] New South Wales, Victoria, Western Australia and the ACT have already introduced full retail contestability. South Australia has introduced retail contestability for large users and intends to introduce full retail contestability, possibly in the next year. Queensland has introduced retail contestability for users consuming at least 100 terajoules per year, but does not intend to proceed further (AGA 2003).

Although most States and Territories are moving towards or already have full retail contestability, some retail prices are still regulated (table 2.4), especially for small retail customers. In addition, some States and Territories have only a few gas retailers.

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[4] Not all gas is sold through retailers. Gas suppliers sell a large proportion of gas directly to large gas users.

[5] Agreement to implement full retail contestability was part of the States and Territories' commitment to the 1997 Natural Gas Pipelines Access Agreement.

Table 2.4 **Gas retailers, by State and Territory**

State/Territory	*Holders of gas retail licences or authorisations*	*Customers subject to retail price regulation*
New South Wales	ActewAGL Retail, AGL Energy Sales and Marketing, AGL Retail Energy, BHP Billiton Petroleum (Bass Strait), BHP Billiton Petroleum, Country Energy, ENERGEX Retail, EnergyAustralia, Esso Australia Resources, Multinet Gas, Origin Energy LPG, TXU Electricity, Wesfarmers Kleenheat Gas	Small retail customers (less than 1 terajoule per year)
Victoria	TXU, Origin Energy Retail, Origin Energy (Vic.), BHP Petroleum (Bass Strait), ENERGEX Retail, EnergyAustralia, Esso Australia Resources, AGL Victoria	Small retail customers (less than 5 terajoules per year)[a]
Queensland	ENERGEX Retail, Origin Energy, Dalby Town Council	Protected retail customers (less than 100 terajoule per year)
South Australia	Origin Energy, Terra Gas Trader, TXU Electricity, AGL South Australia	Small retail customers[b]
Western Australia	AlintaGas, Wesfarmers Kleenheat Gas, Burns and Roe Worley Power Generation (Esperance)	Small use customers (less than 1 terajoule per year)
ACT	ActewAGL Retail, ENERGEX Gas Retail, Country Energy, EnergyAustralia	Retail customers (less than 10 terajoules per year)

a The Minister for Energy, Industries and Resources has the power to regulate standing and deemed offer prices for small retail customers. If a retailer seeks to increase their average prices by more than CPI, the Minister has a standing reference for the Essential Services Commission to investigate any such proposals. The Minister will then make a decision regarding the proposed increases based upon the Essential Services Commission's report and any other relevant information. **b** The South Australian Minister for Energy has retail price setting powers for small South Australian gas customers. This function is expected to be transferred from the Minister to the Essential Services Commission of South Australia, giving that commission the power to set standing contract prices for the State's small gas customers.

Sources: ESC 2002a; Essential Services Commission, pers. comm., 26 November 2003; ESCOSA 2002; South Australian Government, sub. 58, p. 6; Independent Competition and Regulatory Commission, pers. comm., 3 December 2003; ICRC 2003; IPART 2004; ERA 2004a; *Energy Coordination (Gas Tariffs) Regulations 2000* (WA)*; Energy Coordination Act 1994* (WA); *Gas Supply Act 2003* (Qld).

Vertical integration

There is the potential for companies to have operations in other sectors of the gas supply chain (that is, production, transmission, distribution and retail). Some companies, for example, that have distribution operations also have operations in the retail sector (table 2.3). Hunter Gas Users Group noted the involvement of AGL in New South Wales:

> The Australian Gas Light Company (AGL) has an interest in each element of the gas supply chain in New South Wales. AGL is the dominant retailer in the State, supplying gas through two retail arms — AGL Retail Energy Limited and AGL Energy Sales and Marketing Limited …

> The Sydney gas distribution network is owned by AGL Gas Networks (AGLGN), a wholly owned subsidiary of AGL. In addition, the Moomba–Sydney pipeline system is owned by EAPL [Eastern Australian Pipeline]. The legal owner of EAPL is APL, and the beneficial owner of EAPL is the APT. AGL holds 30 per cent of the units in APT. (sub. 4, p. 4)

Some companies are involved in several sectors of the gas supply chain in a number of States (BHP Billiton, sub. DR96, p. 14). Origin Energy, for example, is involved in Victoria as a gas producer, as an operator and part owner of a distribution network and as a retailer. It is also part owner and operator of the South East Australian Gas Pipeline that transports gas from Victoria to South Australia. In South Australia, Origin Energy is also involved as a gas producer, as an operator and part owner of the distribution network and as a retailer (BHP Billiton, sub. DR96, p. 14).

2.2 Demand for gas

Share of energy market

Natural gas consumption in Australia in 2000-01 was around 996 petajoules (table 2.5), which was 20 per cent of total primary energy consumption (up around 8 percentage points since 1981). A range of factors contributed to this increase, including an extension of the market reach of natural gas through growth in the pipeline network; the environmental advantages of gas over other fossil fuels; and the development of major gas-based industrial, mining and electricity generation projects (AGA 2003).

Table 2.5 **Consumption of natural gas and the gas share of primary energy market, by State and Territory, 2000-01[a]**

Market	*Consumption of natural gas*	*Share of primary energy market*
	PJ	%
New South Wales and ACT	142	10
Victoria	251	19
Queensland	79	8
South Australia	135	40
Western Australia	369	51
Tasmania	0	0
Northern Territory	21	27
Australia	**996[b]**	**20**

[a] Includes ethane used as fuel and petrochemical feedstock. [b] Total might not add as a result of rounding.

Source: AGA 2003.

The natural gas share of total primary energy consumption differs significantly across States and Territories (table 2.5). In 2000-01, Western Australia had the highest share (around 50 per cent), while New South Wales, Queensland and Tasmania had shares of 10 per cent or less. The differences across jurisdictions partly reflect resource endowments and industry policy.

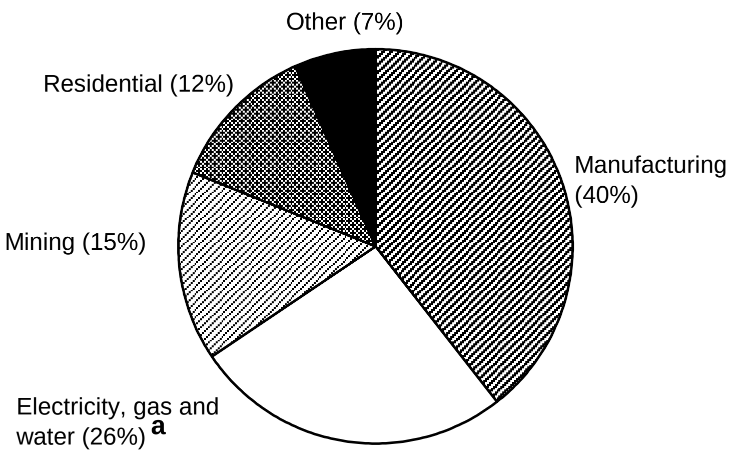
Main sources

The demand for natural gas differs across sectors (figure 2.4). Almost 90 per cent of natural gas is consumed in the industrial and commercial sectors, where there are relatively few, but large, consumers. The manufacturing sector has the highest consumption of natural gas. Some of the largest consumers in the manufacturing sector are:

- the metal product industries, in which gas is used to generate process heat for alumina refineries and ore smelters
- the chemical industry, in which gas is used as a feedstock for fertilisers and plastics
- the glass, brick and cement industries, in which gas is used to generate process heat for kilns (AGA 2003).

Only 12 per cent of natural gas is consumed in the residential sector, where there are a large number of small consumers. This sector uses gas mainly for water heating, space heating and cooking.

Figure 2.4 **Natural gas consumption, by sector, 2001**



[a] Electricity generation accounts for 87 per cent of gas consumed in the electricity, gas and water sector.

Source: AGA 2003.

Natural gas demand by sector differs significantly across States and Territories (table 2.6). In Victoria, around one-third of natural gas is consumed in the residential sector. For most other States and Territories, the proportion is less than 10 per cent. The mining sector consumed a relatively large proportion of natural gas in Western Australia. Electricity generation used a significant proportion in South Australia and the Northern Territory.

Table 2.6 **Natural gas consumption, by State and Territory and sector, 2001[a]**

Petajoules

	NSW[b]	*Vic*	*Qld*	*SA*	*WA*	*NT*	***Total***[c]
Manufacturing	80	93	46	29	145	0	393
Electricity, gas and water	21	28	24	69	99	20	**260**
Mining	0	22	6	23	104	0	**154**
Residential	21	82	1	8	9	0	**122**
Other	20	26	2	6	12	1	**68**
Total[c]	**142**	**251**	**79**	**135**	**369**	**21**	**996**

[a] Includes ethane used as fuel and petrochemical feedstock. [b] Gas consumption in New South Wales includes ACT consumption. [c] Totals might not add as a result of rounding.

Source: AGA 2003.

Forecast

The consumption of natural gas has been forecast to increase both in absolute terms and as a share of total primary energy consumption. ABARE researchers forecast that the consumption of natural gas will almost double to around 1890 petajoules by 2019-20 (Dickson and Noble 2003). This rise would increase the gas share of primary energy consumption from approximately 20 per cent (in 2000-01) to 24 per cent (AGA 2003).

While the consumption of gas is forecast to increase in all sectors (including residential), the most significant increases are forecast in the manufacturing and mining sectors (both in percentage and absolute terms). The manufacturing sector is expected to account for over one-third of forecast growth. In particular, a significant rate of growth is expected in iron and steel manufacturing (AGA 2003).

Electricity generation is another sector in which the consumption of natural gas is forecast to increase significantly. Western Power noted:

> Natural gas is likely to remain the predominant fuel used in electricity generation in Western Australia. Past trends and the interest in the development of new resource projects based on or fuelled by natural gas is an indicator that natural gas consumption will continue to rise for both direct use in processing and as a fuel for electricity

generation. For example, a new 240 MW combined cycle gas turbine unit is currently being considered for construction at Cockburn as part of the State's ongoing power procurement process. (sub. DR115, p. 12)

Electricity generation using natural gas has characteristics that give it advantages over other fuels in meeting peak and some intermediate electricity load. It allows, for example, for the installation of small to medium capacity close to load areas (AGA 2003). Western Power noted that, in Western Australia, gas fired electricity generation is also used for base loads:

> Generating units can be classified as 'base load', 'mid-merit' and 'peaking'. Base load generating units (which predominately comprise coal-fired thermal units like those at Collie and Muja and gas-fired cogeneration units like those of Tiwest and BP Mission) are dispatched first. Then as the electricity load increases during the day, mid-merit plant (such as the gas-fired thermal units at Kwinana) is dispatched. Finally, peaking units (such as the gas turbines at Pinjar) are used to meet peak load during the day. (sub. DR115, p. 7)

Capital costs per unit of generating capacity tend to be lower for gas than for coal fired generation, but operating costs are typically higher (although this is partly offset by higher thermal efficiency in combined cycle technologies). The Institute of Public Affairs also noted the role of natural gas in electricity generation:

> Among the most valuable future roles of gas is in electricity generation. In the context of Australia's low cost coal reserves, gas, unless subsidised by government emission policies, is unlikely to be competitive as a base fuel for electricity. However, gas fired stations are particularly important for peak power provision; because of their considerable flexibility they can be brought on line and taken off line much more rapidly than coal fired stations. Demand trends are bringing a greater call for peak generators. (sub. 2, pp. 2–3)

2.3 Market characteristics of transmission pipelines

Is a transmission pipeline a natural monopoly?

A transmission pipeline could be considered to have a natural monopoly in a particular market if having that single pipeline achieves the efficient least (average) cost of supplying gas to that market, at prevailing levels of demand. However, the existence of a natural monopoly does not mean the market is not contestable or the incumbent service provider has monopoly power. In addition, if demand grows sufficiently, then two pipelines could be efficient, servicing the larger market demand at the least (average) cost.

Transmission gas pipelines have natural monopoly characteristics derived from the following three factors:

- Investments in pipelines are indivisible — that is, they can only be undertaken economically in large increments.
- Economies of scale exist — that is, average costs decline as a pipeline's capacity increases and is used. One pipeline system can generally transport natural gas on a specific route at a lower cost than that of using two pipelines.
- Sunk costs are large. These are investment costs that cannot be recouped if the project is unsuccessful — that is, the investor cannot salvage the facility or sell it to another party without substantial loss.

Indivisibility of investment

For any gas to flow between a gas field and a market, large investment in a pipeline must be incurred, including any costs associated with acquiring easements, survey and site preparation; trenching and backfilling; and pipe delivery, handling and laying. The Duke International Energy Longford–Sydney and Longford–Bells Bay pipelines illustrate the size of these costs. The costs of constructing these two pipelines were $450 million and $400 million respectively (Duke Energy International, sub. 21, p. 5).

Economies of scale

Economies of scale in gas transmission exist in relation to:

- the pipeline diameter
- the expansion of capacity through addition of compressor stations and looping
- a large proportion of total costs that are fixed.

Pipeline diameter

Economies of scale from pipeline diameter arise for the following reasons:

- A pipeline's capacity increases at a higher rate than the capital cost of increasing its diameter. As the Allen Consulting Group (BHP Billiton, sub. 26, attachment, p. 9) pointed out, 'the quantity of steel required (and hence costs) rises proportionally to the radius of the pipeline but the volume rises proportionally to the square of its radius'.
- A pipeline's pressure drops along its length, but the rate at which the pressure drops decreases as the diameter increases (Lawrey 1998; OECD 2000).

- A large proportion of the costs of installing a pipeline are associated with obtaining right of way and laying the pipe. These costs do not vary significantly with the diameter of the pipeline and its capacity.

The Energy Markets Reform Forum (sub. 42, p. 9) noted that increasing the pipeline diameter from 350 millimetres to 450 millimetres increased spare uncompressed capacity by 65 per cent, but increased the capital cost by no more than 5 per cent.[6]

Notwithstanding these economies of scale, there is an economic tradeoff between building a larger diameter pipeline and adding capacity through compressors or looping at a later point in time. This tradeoff is principally determined by the likely life of the pipeline and the expected rate of growth of demand. The tradeoff is between the opportunity cost (including uncertainty) of under used pipeline capacity in the earlier years and the costs of adding capacity through compressor stations and looping in later years. The Australian Pipeline Industry Association (APIA) explained this tradeoff:

> … at the initial design phase of a pipeline, the developer is faced with making a decision on what diameter pipeline to build. Where there is a likelihood of increasing demand for the pipeline's services, the developer will have the choice of constructing a larger diameter pipeline or installing compression (or looping) to meet growing demand.
>
> Other things being the same, larger diameter pipelines are more expensive to build initially but less expensive to expand than smaller pipelines which require compression earlier. The key issue is the uncertainty as to extent and timing of demand growth and the cost of capital for the pipeline … (sub. 44, p. 15)

Pipeline expansions

Low cost compressor stations can increase the capacity of a pipeline. Economies of scale are associated with the size of a compressor because the capital cost of a compressor increases at a rate that is less than the increase in the pressure ratio (and thus capacity). A larger compressor, for example, increases costs by 5 per cent, but increases potential output by more than 5 per cent.

However, there are diminishing returns to additional compressors (ACCC, sub. 48, p. 94) because each has a smaller impact on capacity than the impact of the previous compressor (BHP Billiton, sub. 26, attachment prepared by the Allen Consulting Group, p. 9). Eventually, diseconomies of scale might arise, because the percentage

---

[6] In its draft greenfields guideline, the Australian Competition and Consumer Commission estimated that a 20 per cent increase in pipeline costs would increase capacity by 50 per cent (ACCC 2002a). While the magnitude of the capacity increase is lower in this case, the economies of scale are still evident.

increase in the total pipeline costs from installing an additional compressor will be greater than the percentage increase in capacity, as noted by Sleeman Consulting:

> Initially, the low marginal costs of adding compression capacity will bring down the overall average cost of gas transportation. However, continued addition of compression eventually leads to rising costs. (ACCC, sub. DR101, appendix E, p. 3)

Looping involves duplicating sections of a pipeline. It is significantly more costly than adding compressors, but still has potential for economies of scale, as the percentage increase in capacity can be more than the percentage increase in total cost (because average costs are still declining). However, as with compression, looping at some stage can generate diseconomies of scale.

Large proportion of total costs are fixed

Once a pipeline is constructed, its increased use has economies of scale because its operating costs are low relative to its fixed costs:

> … the incremental cost of serving additional throughput for an existing pipeline with surplus capacity is very low. The direct operating costs (excluding fuel) are unlikely to amount to more than 8 per cent of the total costs of providing the service even when the pipeline is fully compressed. (APIA, sub. 44, p. 18)

As the capacity used increases, the fixed costs are spread over more units of output and average costs decline.

Sunk costs

As noted above, the costs of constructing a pipeline include: gaining access to easements; site preparation; digging trenches; and pipe delivery, handling and laying. Most of these costs cannot be recouped if the pipeline is salvaged or sold for an alternative use. The salvage value of pipes is likely to be low (possibly negative) (Broadman 1986).

Contestability in the transmission pipeline sector

The existence of natural monopoly characteristics does not necessarily mean the absence of competitive pressures. Effective competition can arise from a number of sources, including the threat of other providers entering the market if the incumbent service provider sets prices too high or provides inappropriate quality of service. In circumstances where competitive pressures exist, a service provider faces commercial incentives to operate efficiently by focusing on increasing throughput.

The extent to which the threat of entry restrains the behaviour of an incumbent service provider depends on the barriers to entry to the relevant market. A barrier to entry is something that gives an incumbent service provider an advantage over a potential entrant. In the absence of entry barriers, the mere threat of new entry would elicit competitive performance from an incumbent with a natural monopoly. In the case of transmission pipelines, the main potential sources of barriers to entry, as seen by some, appear to be:

- the large sunk costs
- pipeline licences
- the long-term contracts of incumbent service providers that 'lock in' users or suppliers.

Sunk costs

A market entrant investing in a transmission pipeline faces a risk of incurring large sunk costs if the investment in the pipeline proves to be unsuccessful. The entrant cannot recoup all the investment costs from selling the pipeline or salvaging the pipeline. In the former case, a potential purchaser would unwilling to pay a significant amount for the pipeline because the returns are low. As stated by the Allen Consulting Group:

> … a new entrant's capital would be lost if it entered the gas pipeline market and discovered that it could not operate profitably … (BHP Billiton, sub. 26, attachment, p. 9)

Pipeline licences

A person cannot build a transmission pipeline without a licence. Access to a licence, therefore, is a possible barrier to entry for a potential pipeline investor.

Transmission pipeline licences are granted under State and Territory legislation (table 2.7). In most cases, a licence grants a prospective owner rights over the land on which the pipeline is to be built — an easement. In general, State and Territory legislation enables:

- licensees to gain access to, or an easement over, the land
- landholders to be compensated by the licensee for use of the land.

Table 2.7 **State and Territory legislation for transmission pipeline licences**

State	*Legislation*
New South Wales	*Pipelines Act 1967* (New South Wales)
Victoria	*Pipelines Act 1967* (Victoria)
Queensland	*Petroleum Act 1923*
South Australia	*Petroleum Act 2000*
Tasmania	*Gas Pipelines Act 2000*
Western Australia	*Petroleum Pipeline Act 1969*
Northern Territory	*Energy Pipelines Act*[a]
Australian Capital Territory	*Utilities Act 2000*

[a] As in force at 26 June 2003.

The APT described the process by which a pipeline easement is created:

> In most circumstances, after qualifying that a pipeline route would be approved by the relevant governmental authority, a prospective investor will negotiate with individual land or title holders for a pipeline easement. This is a grant of rights and interests over land by the property owner in favour of the pipeline company, to enter onto the land for the purpose of constructing, operating and maintaining a pipeline. Where negotiations fail, a pipeline operator can be granted a compulsory acquisition order under State laws (negotiations fail in a very small proportion of cases). In both cases, the landholders are compensated and the interest acquired in the land runs with the land, and is registered against the title. Once registered the easement will appear on the certificate of title. (pers. comm., 7 November 2003)

The important issue in establishing the extent to which a licence is a barrier to entry is related to whether State and Territory Governments provide licences on an 'exclusive' basis, or whether another service provider can gain a licence to establish a competing pipeline. The Energy Markets Reform Forum, Electricity Consumers Coalition of South Australia and the Energy Consumers Coalition of Victoria jointly considered that pipeline licences and associated easements are a considerable barrier to entry:

> The reality is that no one can just get a pipeline licence. A licence is an exercise of sovereign power, of eminent domain, whereby the Crown grants an interest in and over public and private lands. No Minister will grant such licences willy-nilly. An easement for a pipeline is a strategic natural resource. (sub. DR94, p. 12)
>
> The idea that another service provider could get a parallel easement is rather fanciful. What Minister would grant a licence for duplicate infrastructure and face the wrath of thousands of landholders angered by seeing their lands dug up a second time? For all practical purposes, an easement from point A to point B is a 'first-come first-served' once-off opportunity. (sub. DR94, p. 34)

Furthermore, the Energy Markets Reform Forum argued that the exclusive or limited right to easements creates infrastructure monopolies.

> … [the argument] advanced on behalf of infrastructure owners along the lines that:
>
> - Monopoly does not exist (because there is always some competition e.g. electricity versus gas)
>
> … is quite false, as monopolies are based on exclusive or limited easements or right of way granted by Parliament, that is, Parliaments grant monopoly privileges as unlimited freedom of entry does not exist. (sub. 30, p. 4)

In contrast, the APT considered easement rights did not create a monopoly for an existing pipeline owner, noting:

> - Where there is an existing pipeline, anyone can get access either through negotiating access to the easement. There are numerous examples of this in NSW. There are multiple pipelines that have access to AGL Gas Networks' easement for its trunk main which traverses from Wollongong to Newcastle. At various points there is petroleum fuels pipeline, Duke’s EGP [Duke Energy’s Eastern Gas Pipeline], a Sydney Water pipeline, and the Gorodok ethane pipeline. APT's easement for the MSP [Moomba–Sydney pipeline] has Gorodok's ethane pipeline in it. Undoubtedly there will be other examples around the country.
> - It is always possible to obtain an easement which is either parallel to or overlaps an existing easement.
> - Existence of an existing easement is likely to facilitate an application for an additional easement as the granting of an existing easement will have already affected the land (to the extent it has) and there will then be minimal loss of amenity through the granting of an additional easement. (APT, pers. comm., 6 December 2003)

In addition, the APT observed that some easements are government owned and available for all potential pipeline investors:

> In some circumstances, an easement is developed and owned by government and is available for use by all potential infrastructure investors. For example, the easement on which the Ballera–Mount Isa pipeline is located is a dedicated infrastructure easement owned by the Queensland Government. (APT, pers. comm., 7 November 2003)

In signing the Council of Australian Governments Natural Gas Pipelines Access Agreement (1997), State and Territory Governments agreed ‘to remove legislative or regulatory barriers to both inter- and intra-jurisdictional trade in gas’ and in particular not to use licensing to ‘restrict the construction or operation of pipelines that could deliver gas to the same market as a licensed pipeline’ (box 2.1).

Although pipeline licensing and the creation of easements can possibly add to the barriers to entry associated with transmission pipelines through the contribution to sunk costs, there is evidence to suggest that licences are not granted on an exclusive or ‘once-off’ basis.

Box 2.1 **1997 Natural Gas Pipelines Access Agreement — Annex F Licensing Principles**

The licensing requirements and conditions will be consistent with the requirements of COAG [Council of Australian Governments] agreements in relation to free and fair trade in gas (for example, the agreement to remove legislative or regulatory barriers to both inter- and intra-jurisdictional trade in gas).

Specifically, the Parties agree to the following Licensing Principles:

1. Licences to operate natural gas pipelines to be unbundled from any other type of licence and open to all appropriately qualified pipeline service operators;
2. Licensing will not be used to restrict the construction or operation of pipelines that could deliver gas to the same market as a licensed pipeline;
3. A licence will not limit the services an operator may provide;
4. By-pass to, and inter-connection in order to supply gas to, contestable customers should be allowed if the operator has the necessary operating licences and can meet the requirements of the relevant network operating procedures (contestable customers being customers who are able to choose their supplier of gas from any appropriately licensed retailer or other supplier in accordance with the phase in timetable as contained in Annex H);
5. Licence conditions may include an obligation to connect customers onto the natural gas pipeline network. This may include an obligation to undertake minor or infill extensions to the geographic range of the network;
6. There will be full transparency in decision-making on licensing through public notification and accountability for decisions.

Establishing a customer base

For a new entrant to compete with an incumbent service provider, it needs to capture a large share of the existing market or capture increases in the total market. The incumbent with a large share of the market with the advantage of economies of scale might have a significant cost advantage compared with the new entrant. With this cost advantage, the incumbent service provider’s long-term contracts with large users could constrain the new entrant’s ability to capture a significant share of the existing market. Unless demand increases significantly, it is usually less costly for an incumbent service provider to increase capacity to meet new demand, than for a new entrant to build a pipeline. The Australian Competition and Consumer Commission (ACCC) noted the advantage of an incumbent service provider over a potential entrant:

> Typically looping is significantly more expensive per unit of capacity than compression, but still significantly more economical than the construction of a brand

new pipeline by another party. This is because the pipeliner looping its pipe has significant common costs in operation and can also save on construction — given it has access to the current easement and much of the necessary construction infrastructure in place. Looping also provides an ability for a pipeline company to incrementally increase capacity as demand grows, rather than having to invest in a whole new pipeline in one lump sum. (sub. 48, p. 94)

Contestability and growing demand

As the demand for natural gas in Australia has grown and the barriers to interstate trade have been reduced, the gas transmission sector has become more contestable and competing pipelines have emerged (section 2.5). New entrants appear to have been able to secure sufficient new demand to make entry viable and to mitigate some risks associated with sunk costs if a project is unsuccessful.

Other factors that might have contributed to the emergence of this competition include:

- the need to ensure the security and diversity of natural gas supply in downstream markets
- the decline in supply, and the increasing costs of extraction, of gas from older gas fields
- discovery and development of new gas supply sources.

Concentration

As the gas sector further develops, competition between transmission pipelines could depend on whether there is increased concentration of ownership, through acquisitions and mergers (particularly horizontal integration).

Competition for new development

Competition between prospective pipeline investors to build new pipelines (bringing new supplies of natural gas to various markets) can also limit a pipeline owner's ability to exert market power and earn excess profits associated with any resulting monopoly (monopoly rents). The competition between investors could be:

- implicit — through competition to sign up foundation customers to underwrite pipeline investments
- explicit — through a competitive tender process.

Foundation customers are important for the development of new pipelines. In general, new pipelines will not be developed without a proportion of the capacity already contracted, as noted by BHP Billiton:

> The project histories for the DMP [Darwin–Moomba pipeline] and PNG [Papua New Guinea Pipeline] … 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. (sub. 26, p. 63)

Potential foundation customers are likely to consider the competitiveness of all potential sources of natural gas before entering into foundation contracts:

> 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. (BHP Billiton, sub. 26, p. 63)

A prospective pipeline investor, therefore, will often compete with another prospective investor to sign up foundation customers to underwrite its investment. BHP Billiton described the competition for foundation customers between Epic Energy (for the Darwin–Moomba pipeline) and the APT (for the Papua New Guinea Pipeline):

> … 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 [Darwin–Moomba pipeline] was now directly competing with another proposed pipeline for foundation customers. (sub. 26, p. 57)

This competition is likely to result in a significant proportion of the potential monopoly rents being dissipated through offers of lower prices to these foundation customers.

Competition can also be explicit. If a user or government wants a new pipeline built, they might call for tenders from a number of potential pipeline investors. If the tender is competitive and awarded to the investor that will provide the best terms and conditions, then a pipeline owner's ability to earn monopoly profits is limited.

A number of pipelines in Australia have been built under these conditions — for example, the Goldfields Gas Pipeline:

> The tariffs which are part of the regime established under the State Agreement arose out of the Western Australian Government's competitive tender, and therefore resulted from a contestable process. (APT, sub. 55, p. 21)

The ACCC noted that competition for new developments might not prevent an eventual pipeline owner from exerting market power over some users (those seeking access after the pipeline is built or those renegotiating contracts):

> Even if there is competition in the construction phase of a pipeline, the eventual pipeline owner may still exercise market power unless third party tariffs are locked in as part of the competitive process. There may also be an incentive for the upstream or downstream users to share rents with the pipeline company in order to restrict competition in dependent markets. (sub. 48, p. 25)

However, even third party users might have options available other than seeking access to the pipeline and therefore might have some bargaining power in its negotiations with the pipeline owner (see below).

Other forces that constrain market power

Other forces (exogenous to the pipeline industry) also might constrain the ability of a transmission pipeline owner to exert market power (Broadman 1986), including:

- the bargaining power of users
- the price elasticity of demand for gas transmission services.

Where market power is constrained, a service provider faces commercial incentives to operate efficiently by focusing on increasing throughput.

Bargaining power of users

The bargaining power of users and owners of transmission pipelines rests on their ability to threaten not to deal with the other party. The balance of power depends on the credibility and effectiveness of each party's threat. It also reflects which party would incur the highest cost if the transaction did not take place. The ACCC (2001b) noted:

> To determine if countervailing power is relevant, the analyst needs to consider the bargaining position of buyers and sellers. In particular, it is important to consider which parties will lose the most from any failure to reach an agreement to trade the relevant product. For countervailing power to exist in a market that otherwise is deficient in competition, any loses from a break-down in bargaining need to be predominantly borne by the seller. (ACCC 2001b, p. 13)

Given that many users enter into long-term contracts with pipeline owners, bargaining between users and pipeline owners occurs when these contracts are agreed, and if and when they expire. A number of factors might influence the bargaining power of users relative to pipeline owners, including:

- the size and concentration of users
- the forming of foundation contracts
- the ability of users to vertically integrate — that is, to build their own pipeline.

Size and concentration of users

The smaller the number of users of a transmission pipeline and/or the larger their purchases, the greater is the bargaining power of users in relation to pipeline owners. This is because the costs to the pipeline operator from losing one user would be large.

In general, the concentration of users serviced by transmission pipelines is high. Across all major pipelines, the top four users ship over 90 per cent of the natural gas on average. APIA noted that use is also concentrated across pipelines, which enhances users' bargaining power:

> … different pipelines will often have the same major customers, whether a gas retailer (such as AGL) or a major industrial consumer (such as BHP Billiton). Consequently, pipeline customers tend to be significant and experienced users of pipeline services. Given that information on the economics of pipelines is readily available from engineering consultancy firms, pipeline customers are well informed and well placed to negotiate for the provision of services. (sub. 44, p. 18)

Dissagregated information on Epic Energy's pipelines (in September 2003) also shows a high level of concentration of users serviced by transmission pipelines (table 2.8).

Even if the demand of a user or potential user is large, the credibility and effectiveness of the threat not to deal with the pipeline owner depends on the other options that exist for that user or potential user. These options might include dealing with another pipeline owner, substituting another fuel for natural gas, locating elsewhere, not proceeding with a project, or purchasing rather than manufacturing an input. Orica, for example, noted that once its natural gas contract expired it had the options of continuing to manufacture or importing ammonia. It also noted that if it decided to import ammonia, the revenue of pipeline owners would be significantly reduced:

> Orica's existing contract for the supply of natural gas to Kooragang Island is due to expire in late 2005. The pending expiry has initiated an investigation into options for the long-term supply of ammonia to the Kooragang Island site. The company has identified two major options available to secure a long-term supply of ammonia.
>
> 1. Negotiate a new supply contract of natural gas which would allow the ammonia produced to be competitive with foreign overseas imports.

2. Close down the ammonia plant and negotiate a long-term supply contract to import ammonia from foreign manufacturing plant.

… the implications of moving to imported product would have far reaching effects including … [a] significant reduction of natural gas transported to Kooragang Island and income earned by transmission and distribution pipeline owners … (sub. 28, p. 5)

Table 2.8 **Concentration of users on Epic Energy's transmission pipelines, September 2003**

Transmission pipeline	*Total number of users*	*Contracted capacity used by largest three users*	*Users' industry category*	*Proportion of contracted pipeline capacity*
		%		%
Dampier–Bunbury	11	78.0	Manufacturing/ minerals processing	62
			Retail	11
			Electricity generation	27
Moomba–Adelaide	4	99.8	Manufacturing/ minerals processing	10
			Retail	16
			Electricity generation	74
Ballera–Wallumbilla	3	100.0	Manufacturing/ minerals processing	95
			Retail	5
			Electricity generation	..

.. Not applicable.

Source: Epic Energy, sub. 37, pp. 15–16.

Although such alternatives might provide some users with a degree of bargaining power relative to a pipeline owner, other users might not be in such a position. A user that has no real fuel or energy substitutes and is located in a market that is serviced by a single transmission pipeline (for which there is excess demand) is unlikely to have significant bargaining power. Western Power argued this, noting:

… [as] contracts expire, and WPC's [Western Power Corporation's] needs for gas transmission capacity increase, WPC is finding that it has little or no bargaining power. There are a number of large users in the south west of Western Australia, all with a critical need for gas and all competing for the limited amount of the DBNGP [Dampier–Bunbury pipeline] transmission capacity that is available. … In circumstances where WPC has a large sunk investment in gas-fired generators and there are no alternative gas or gas transportation options, WPC cannot make a credible threat to not deal with the owner of the DBNGP. (sub. DR115, p. 16)

Worsley Alumina also argued its bargaining power was constrained by some of these factors:

> In the present environment, the user will incur the highest cost if it is unable to secure gas transmission capacity. In Western Australia, users lack any real ability to credibly make a threat to the owners of the DBNGP [Dampier–Bunbury pipeline] that users will cease contracting to access gas transmission services as users' bargaining power is severely constrained by a number of factors …
>
> (a) lack of alternative transmission pipelines;
>
> (b) the extensive sunk costs in infrastructure that can only be fuelled by natural gas, for example gas turbines;
>
> (c) a very limited ability to substitute alternative fuels for natural gas, especially in industrial applications where product quality considerations may require the use of natural gas, for example in calcination in alumina refineries; and
>
> (d) environmental agreements. (sub. DR110, p. 4)

Similarly, WMC Resources argued (with particular reference to the Western Australian goldfields region) that users lacked bargaining power because they lacked credible alternatives:

> … there appears to be little significance attributed to the lack of bargaining power of pipeline users, which are completely dependent upon the services of a particular pipeline. That's particularly the case, I think, in Western Australia, particularly in the goldfields region and a lot of the mining and industrial clients there. (trans., p. 923)

Although, Goldfields Gas Transmission argued other options were available in the goldfields region, noting that:

> … while the GGP [Goldfields Gas Pipeline] on the face of it would appear to have a monopoly in respect to gas transmission services in the regions it traverses, it certainly does not have a monopoly with respect to electricity supply, or for the supply of energy for electricity generation. (sub. 16, p. 6)

Foundation contracts

As noted, companies generally do not build transmission pipelines unless there is significant demand for pipeline capacity by gas suppliers and large users. The foundation contracts negotiated with these parties underwrite the pipeline investment (IEA 2000) and can reduce some of the pipeline investor's risks. ExxonMobil noted:

> … large [gas] projects of this nature require large investments and bear significant risk both by the upstream gas producer and the pipeline developer. Therefore, fundamental to developing these new opportunities are commercially negotiated offtake and foundation shipper agreements … The fact is the pipeline would not be built and benefits from competitive gas supplies would not be realised without the foundation volumes to underwrite the pipeline's development. (sub. 8, pp. 4–5)

Similarly, the Northern Territory Treasury observed:

> … new investment in gas infrastructure in the [Northern] Territory has been, and is likely to be, heavily dependent upon procurement of foundation customers. (sub. 41, p. 1)

The Australian Petroleum Production and Exploration Association also commented:

> … the majority of … new pipelines have been built on the strength of long-term transportation agreements with foundation shippers … (sub. 6, p. 2)

Before entering a contract for pipeline capacity, a foundation customer seeks terms and conditions commercially favourable for its business. It is not unreasonable to presume that users have some bargaining power in negotiating these contracts, for the following reasons:

- Downstream users are unlikely to have made large investments in capital associated with natural gas before negotiating contracts with upstream suppliers and pipeline owners, so they are potentially in a position to use other fuels or locate where the costs of natural gas are lower.
- Users might have sought to have the pipeline built through a competitive bidding process, so can choose the best terms and conditions offered by prospective pipeline investors.
- A pipeline investor has commercial imperatives (including the securing of project finance) to have contracts covering as much of the pipeline's capacity as possible before construction. It will actively seek to sign contracts with large users and, therefore, presumably offer terms and conditions that will attract these users.

Epic Energy noted the bargaining power of customers in negotiating foundation contracts:

> Prospective shippers [customers] negotiating the foundation contracts are … few in number, commercially sophisticated and have the resources necessary for effective negotiation with the pipeline owner. Their commitment is required to secure project financing and to permit pipeline construction to proceed. (sub. 37, p. 43)

ExxonMobil also highlighted the competitive pressures on a pipeline developer in foundation contract negotiations:

> It needs to be remembered that in the negotiation of the tariffs the competitive forces on the pipeline developer are that the tariffs must enable that source of gas to reach the market at a competitive price. (sub. 8, p. 5)

Foundation contracts are long term and beneficial for pipeline investors and foundation customers.

- For pipeline investors, long-term contracts are essential for underwriting the investment in the pipeline (given that these investments are long term in nature).
- For foundation customers, long-term contracts provide long-term security of supply, which is especially important if they have invested in long-term capital associated with natural gas use. Foundation customers might also be able to negotiate contracts that are evergreen — that is, there is an option to renew at the end of the contract.

Another benefit of long-term contracts is that they reduce the scope for opportunistic behaviour whereby one party refuses to do business except on unreasonable terms.

'Most favoured nation' clauses are commonly used in foundation contracts (ACCC, trans., p. 335). These clauses ensure that if a pipeline owner sells capacity to other users at a lower price, the foundation customer is also charged this price and thus is not competitively disadvantaged. ExxonMobil explained that without these clauses, other customers could gain a competitive advantage that:

> … may place significant risk on the foundation shipper particularly for growth volumes. This would seem an unacceptable position for a foundation shipper. The fact is the pipeline would not be built and benefits from competitive gas supplies would not be realised without the foundation volumes to underwrite the pipeline's development. To mitigate this risk a foundation shipper may endeavour to negotiate matching rights. (sub. 8, p. 5)

The use of most favoured nation clauses provides evidence of the bargaining power of foundation customers relative to pipeline investors.

In addition, customers with large foundation contracts might provide some constraint on a service provider's market power after construction. If a pipeline seeks to increase the price above that determined under the foundation contract, foundation customers might have an incentive to sell their capacity to potential users and thereby act as a competitor to the service provider.

Vertical integration

A user gains some bargaining power if it can credibly threaten to build its own pipeline. This threat is more credible for large users or a group of users. The ability of users to vertically integrate was noted by APIA:

> … recent experience has highlighted the fact that customers themselves are able to effectively vertically integrate upstream into the provision of pipeline services. A good example of pipeline users executing such a strategy is the South East Australia Gas Pipeline … (sub. 44, p. 19)

For the majority of small users, however, the ability to integrate vertically is limited and thus the threat is not credible.

Price elasticity of demand

The price elasticity of demand is a measure of the responsiveness of demand for a good or service to a change in its price. Formally, it is the percentage change in quantity that would result from a 1 per cent change in price. Where the percentage change in quantity is greater than one, demand is elastic. Where it is less than one, demand is inelastic (Pindyck and Rubinfeld 1998).

Elasticities indicate a service provider's ability to exert market power. A service provider facing low elasticity of demand for transmission services has market power because it can increase the price without revenues falling. Typically, elasticity of demand is higher in the long run.

The demand for transmission pipeline services is a 'derived' demand. That is, it is derived from the demand for the natural gas, which is derived from the demand for a final product, such as aluminium. Four factors influence the price elasticity of demand for a service with derived demand:

- the elasticity of demand for the final product
- the proportion of the final product's total costs that the service comprises
- the availability of substitutes for the service
- the elasticity of supply of other input providers.

End users' elasticity of demand

If demand for a final good is elastic, then demand for services or products in its supply chain should also be relatively elastic. This is because the more elastic the demand for the final good, the greater is the effect on the quantity demanded of this final good if the price rises (because input costs have increased). This, in turn, has a greater effect on the quantity of inputs purchased to produce this final good.

The main end users of natural gas are in the manufacturing, mining and electricity generation sectors. A number of businesses in these sectors operate under competitive conditions, so would probably have relatively high demand elasticities. Many of the large natural gas users in the manufacturing and mining sectors compete in world markets. A number of inquiry participants noted the international competition faced by these users:

> APIA notes that the gas transport service provided by pipeline companies is an input into a broad range of final products. For example, the final product may be aluminium from a smelter destined for export which may exhibit relatively high demand elasticity or it may be health services (that is, major hospitals) which are likely to exhibit extremely low demand elasticity. Overall, the largest direct customers for pipeline services tend to be energy intensive industries such as smelting and refining where the final products are likely to be mainly exported and faced by significant demand elasticity. (APIA, sub. 44, p. 23)

> Ammonia produced by this [Orica's Kooragang Island plant] plant competes against imports that provide raw material supply to downstream fertiliser and industrial chemical production. (Orica, sub. 28, p. 3)

> CSBP consumes natural gas, primarily as feedstock and also for energy, in the manufacture of a range of chemicals and fertilisers, which are supplied into highly competitive domestic and international markets. (CSBP, sub. 33, p. 1)

> WMC [Resources] has a strong interest in the maintenance of a Gas Access Regime which … facilitates WMC's need to ensure its international cost competitiveness … (WMC Resources, sub. 43, p. 4)

In the electricity generation sector, the electricity generated using natural gas faces competition from the electricity generated using other fuels, such as coal. Currently, natural gas competes in the provision of electricity for peak and intermediate demand.

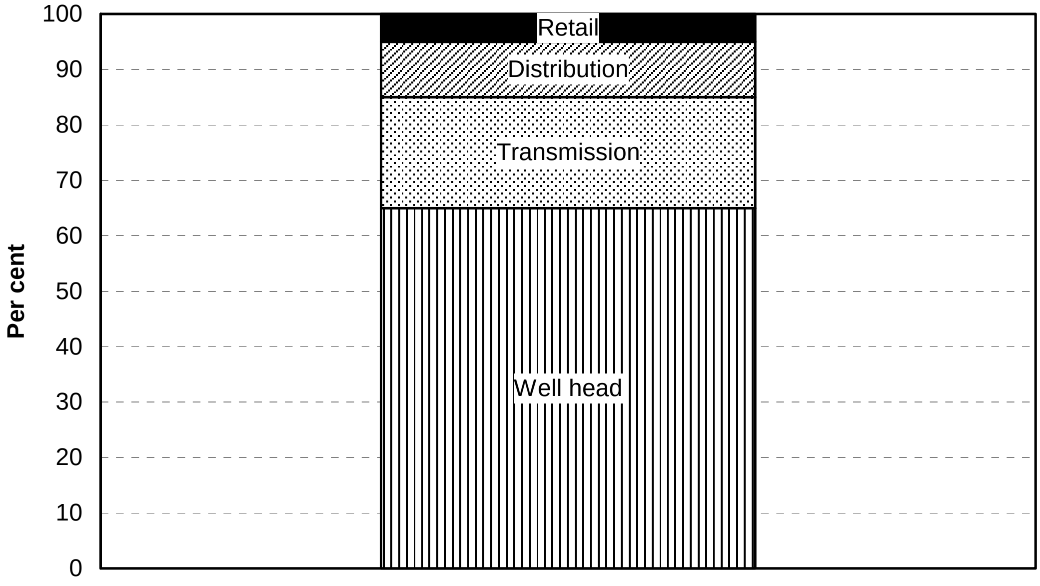
Share of transmission cost in total costs

The smaller the proportion of a final product's total costs that an input service comprises, the lower is the elasticity of demand for that service. A rise in the price of an input that is a small part of total costs will have a small impact on the final price (even if the input's price rises significantly and the cost is passed on fully).

The evidence suggests the gas transmission share of the total cost of many final products is small. The transmission cost is only about 20 per cent of the cost of delivered natural gas (figure 2.5), which is only a small share of the total costs of a product. APIA noted:

> Gas transmission services comprise only a small proportion of the total delivered cost of gas. Even for major industrials the transport component is unlikely to exceed one third of the total cost. For example, the indicative transport tariff on the [Moomba–Sydney pipeline] is currently around 66 cents/GJ (Moomba to Wilton firm forward service at 100 per cent load factor) out of an estimated $3.30–$3.71/GJ (GST exclusive) total delivered wholesale price of gas or approximately 20 per cent of the total. In turn, the wholesale gas price will generally represent a small proportion of the total cost of the final product although this will vary depending on the product. (sub. 44, p. 24)

Figure 2.5 **Composition of major users' natural gas costs**



Source: Australian Gas Association, pers. comm., 18 July 2003.

Incitec estimates provide one example of the transmission share of total costs. The National Competition Council reported these estimates in its coverage decision on the Moomba–Sydney pipeline:

> Gas represents 45 per cent of Incitec's total manufacturing cost and 80 per cent of variable cost for the company's Newcastle plant. Further, Incitec informs the [National Competition] Council that transmission pipeline charges represent about 15 per cent of delivered gas costs. (NCC 2002a, para. 7.427)

Goldfields Gas Transmission provided another example:

> … with most of the users — certainly on the goldfields — the transmission costs comprise only a very small portion — a very small percentage — of the user's operating costs and, if you put that in the context of their total costs, it is less than 5 per cent. (trans., p. 60)

The small gas transmission share of total costs might enhance the ability of a service provider to exert market power. However, this factor can be overshadowed if there are significant available substitutes.

Availability of substitutes

The greater the availability of substitutes, the more elastic is the demand for a good or service. Possible substitutes for the services of a transmission pipeline (other than another competing pipeline) are:

- intermodal substitutes
- energy substitutes — other fuel and energy sources
- other options, such as importing feedstock.

The two main methods of transporting natural gas from a gas field to the market are (1) onshore or offshore high pressure transmission pipelines and (2) tankers that transport gas over road, rail or sea after it is converted into LNG. The LNG is re-gasified at the point of consumption. Except in limited circumstances, transporting natural gas in onshore transmission pipelines is the least costly method (Leitzinger and Collette 2002; OECD 2000). The International Energy Agency (IEA 1994) reported that this method is less costly than transporting LNG for distances under 4000 kilometres.

The demand for the services of gas transmission pipelines is derived from end users' demand for natural gas. Fuel and energy sources that substitute for natural gas, therefore, provide an alternative to the services of transmission pipelines.

The extent to which fuel and energy substitutes exert competitive pressure on transmission pipeline services depends on the propensity of end users to switch towards these substitutes. The propensity to substitute depends on the ease with which another fuel or energy source can replace natural gas in a particular productive process (rate of technical substitution) and the relative prices of natural gas and its substitutes. This propensity will vary considerably across sectors and individual users. It also varies in the short and long term.

Substitute fuel and energy sources can replace natural gas in many productive processes. The manufacturing, electricity generation and mining sectors use about 80 per cent of the natural gas transported in transmission pipelines. In these sectors, natural gas is used for a range of purposes and the energy substitutes are varied, for example:

- In the mining sector, natural gas is used for generating electricity. Possible substitutes for natural gas include electricity from an existing grid, and diesel (Goldfields Gas Transmission, sub. 16).
- In the manufacturing sector, natural gas is used as a chemical feedstock for making products, such as plastic. Possible substitutes for natural gas include naptha and liquefied petroleum gas (LPG) (IC 1995a).

- In the electricity generation sector, possible substitutes for natural gas include coal, fuel oil, hydro and wind (IC 1995a).

The ability of a user to replace natural gas with other fuels or energy sources is limited in the short term if a plant is built to run only on natural gas (a purpose-built gas fired electricity generator)[7] or if it has signed long-term contracts to use natural gas. The ability of a user to replace natural gas is higher in the short term if another fuel or energy source is a close substitute and the user can switch to it relatively easily. One example is a multifired electricity generator that can use natural gas and fuel oil, such as the Torrens Island Power Station:

> The generator has eight steam turbines that generate 1280 MW [mega watts]. Burning either natural gas or fuel oil, generation is split across two sections at the Torrens Island Power Station, both of which are dual fuel capable. (TXU Australia, sub. 11, pp. 4–5)

Western Power also explained that many of its generator plants run on two types of fuel (sub. DR115, pp. 7–8). By using multiple fuels, a generator is able to increase security of supply and reduce its risk. However, there is a tradeoff between this increased security and the gains available from fuel specialisation.

In the long term, the ability of a user to replace natural gas with other fuel or energy sources in a productive process might be limited only where they are not close substitutes. One example might be an industrial user that uses natural gas for noninterruptible process purposes. In this case, natural gas has inherent advantages over other fuels, because it is of more uniform quality and is easier to handle (IEA 2002d). Another example is the production of ammonia (used to produce fertilisers) where there are no competitive substitutes for natural gas (IC 1995a).

Goldfields Gas Transmission provided examples of how the mining sector can easily use substitute fuels and energy sources for natural gas in power generation:

> The Goldfields Gas Pipeline operates in a market context where the majority of its capacity is devoted to the delivery of gas specifically for the purpose of power generation for major mining and processing activities. Only a small proportion of the gas is used as gas for its inherent qualities. The power generated using Goldfields Gas Pipeline gas competes:
>
> - in the Pilbara, with power delivered by company-owned high voltage transmission lines from coastal power stations;
> - in the northern goldfields, with power generated in remote power stations using diesel as a fuel;

[7] After an investment is sunk, users will only convert to another source of fuel when the capital costs of conversion are less than the energy savings resulting from the conversion.

- in the eastern goldfields, with power delivered by high-voltage transmission lines from power stations connected to the State's South West Interconnected System … (sub. 16, p. 5)

However, even if a substitute energy source can be used to replace natural gas in a productive process, the extent to which this substitute exerts competitive pressure depends on its price (cost structure). The ACCC noted:

> … if the final supply price of gas is the lowest of all alternative energy sources, then the gas supplier has an incentive to price up to the cost of the next best alternative. If the cost of supplying gas is considerably below the cost of its next most efficient alternative, then the gas supply chain may be able to accrue substantial monopoly profits.
>
> Thus, the extent to which alternative energy sources will constrain the exercise of market power by a pipeline owner will depend on the circumstances of each energy source including the underlying cost functions. (sub. 48, p. 21)

Frontier Economics, referring specifically to the Goldfields Gas Pipeline, noted the importance of the price of substitute energy sources in determining the competitive pressure exerted by substitutes:

> Of course, market power and competition are matters of degree. This can readily be illustrated by means of our simple numerical example. If we suppose that $110 is the all-inclusive unit cost of producing electricity by means of gas, we may refer to that as the price that would prevail if this electricity were produced in a highly competitive market. (Any price greater than $110 would yield monopoly profit.) We may then enquire what competitive pressure is placed on GGT [Goldfields Gas Transmission] by the possibility that there are alternative means by which electricity may be supplied to a large mine.
>
> … if other sources of power were to maintain their prices at $137.50, then GGT [Goldfields Gas Transmission] could increase its price by 50 per cent (from $45 to $67.5) which would increase the cost of electricity from $110 to $132.50: and the cost of obtaining electricity by means of gas would still be below that of alternative sources of electricity … (WMC Resources, sub. DR99, attachment, p. 9)

Similarly, WMC Resources noted:

> … if you're a third party wanting one terajoule per day down a pipeline, you have little or no bargaining power and you're vulnerable to monopoly rents, because there's no credible alternative. You will hear things like, 'Oh, but coal or diesel is an alternative.' Well, the price of gas is $2.50 a gigajoule and diesel is, what, $12 a gigajoule. Sure, it's a threat, but it's not very credible. (trans, p. 928)

Referring to a number of Australian Competition Tribunal decisions, the ACCC also argued that other energy sources do not effectively constrain natural gas prices:

> There is an argument that the gas supply chain (including the pipeline sector) is constrained from exercising market power owing to competition from other energy

> sources. This argument raises the prospect that the relevant product market may include other energy sources rather than being a gas specific market.
>
> However, in the past the [Australian Competition] Tribunal has consistently found that gas prices are not effectively constrained by alternative energy sources and has found the product market to be a gas specific market. (sub. 48, p. 19)

On the other hand, Epic Energy noted that other fuels and energy sources do provide some constraint on the price at which gas is delivered by a new pipeline:

> A new transmission pipeline delivers gas into a market in which there are alternative energy supplies (gas supplied through other pipelines, electricity, coal and oil-based fuels). To be viable, the new pipeline must be able to deliver gas at a price which is low enough to ensure that a share of the energy market is captured sufficient to generate the revenues necessary to recover the costs of the investment and a return on that investment. The price at which gas can be delivered will be constrained by the prices at which alternative sources of energy can be supplied. (sub. 37, p. 40)

Elasticity of supply for other inputs

The more elastic the supply of other inputs in the production of a final good, the more elastic is the demand for transmission pipeline services. This is because the maximum price that a service provider can receive is limited by (1) the amount that consumers are willing to pay for the final good and (2) the price that other input providers are willing to accept for their services. If the price charged by the service provider increases, then the price of the final good must rise and/or other input providers must accept a lower price for their services. The less the ability of other input providers to accept a lower price, the greater is the adjustment required by consumers (that is, the higher is the change in the price of and the demand for the final product) and, therefore, the more elastic the demand for the transmission pipeline services.

FINDING 2.1

Transmission pipelines have natural monopoly characteristics. The scope for transmission pipeline owners to exercise market power arising from such characteristics can be constrained by a number of factors, including:

- *the availability of substitutes — that is, the presence of a competing pipeline in the end market and/or of substitute fuel and energy sources*
- *the size and concentration of users and the competitive nature of foundation contracts*
- *the elasticity of demand for the final products, for which natural gas is an input.*

The extent to which these factors constrain market power differs across pipelines.

2.4 Market characteristics of distribution networks

Is a distribution network a natural monopoly?

Distribution networks have natural monopoly characteristics derived from the following three factors:

- Investment in networks is indivisible — that is, they can only be undertaken economically in large increments.
- Economies of density and scale exist — that is, average costs decline as the number of customers serviced by a given network (and units of output) increases.
- Sunk costs are large — that is, investment costs cannot be recouped. If the project is unsuccessful, then the investment cannot be moved or sold to another party without substantial loss.

Indivisible investment

As with transmission, investments in distribution networks are typically lumpy and large. For any gas to flow from a city gate to end users, large investment costs must be incurred. The costs might include those associated with the pipes; trenching and backfilling; market development activities; pipe delivery, handling and laying; and pressure reducing stations.

Economies of density and scale

As with other network industries, gas distribution networks exhibit economies of density, which means having a single network achieves the efficient least (average) cost of supplying natural gas to end users. Economies of density arise because once a gas distributor has incurred the costs of installing a gas main down a street, the marginal cost of connecting another house or building to the gas main is small (OECD 2000). As the network serves more customers, the large fixed costs are spread across more units of output. The Essential Services Commission noted these characteristics:

> Density economies reflect efficiencies related to network construction and operation. Existing networks that are in place to provide service at a given location can usually provide service to nearby locations at low incremental cost. When the incremental cost of extending the gas distribution network is lower than the average cost of service, network expansions cause average costs to decline. Productive efficiencies are thereby realised and lower prices are possible for new and existing gas delivery customers. … the gas distribution business involves ongoing network extensions to serve new

> customers. These network extensions often allow the company to achieve continued density economies, so the gas distribution business naturally gives rise to ongoing production efficiencies that reinforce the industry's natural monopoly position. (sub. DR112, p. 11)

As with transmission, a distribution network exhibits economies of scale with increased use, because its operating costs are low relative to its fixed costs. As the capacity used increases, the fixed costs are spread over more units of output and average costs decline. These economies of scale are partly independent of the economies of density. That is, while the density of customers on two systems might be the same, if customers on one system use more gas on average than that used by customers on the other system, the extent to which economies of scale are exploited will differ.

Sunk costs

The costs of constructing a network are large and most of the investment could not be recouped if the network (pipe) is salvaged and sold for an alternative use.

Contestability in the distribution network sector

As noted, the existence of natural monopoly characteristics does not necessarily mean the absence of competitive pressures. Effective competition can arise from a number of sources, including the threat of other providers entering the market. However, the threat of entry depends on the size of the barriers to entry. In circumstances where competitive pressures exist, a service provider faces commercial incentives to operate efficiently by focusing on increasing throughput.

In distribution networks, the main potential barrier to entry appears to be the large sunk costs, which tend to give the incumbent service provider a 'first mover' advantage. This advantage arises because only one network will be viable (especially when most users are small) for a given region or market. To be profitable, a potential entrant would need to capture a significant proportion of the incumbent's market (in effect, making the incumbent unprofitable). However, an incumbent that is known in the market and has an established customer base would be at an advantage over a potential entrant.

In addition, distribution network supply cannot be easily tailored to demand and there can be considerable excess capacity. This means that (in contrast to the transmission pipeline sector), even if there is a large increase in demand, duplication of the network is unlikely to occur:

… at the level of the individual small customer, reticulation supply has considerable excess capacity, making it infeasible to duplicate supply, even where there are substantial increases in demand. In contrast, the capacity of gas transmission pipelines can usually be tailored more closely to demand, and consequently any lumpy increases in demand (for example, a new power station or energy-intensive industry) can provide an opportunity for a new competing pipeline to enter, and to achieve minimum efficient scale. (Essential Services Commission, sub. DR112, p. 11)

If the demand for gas outgrows the capacity of an existing network, the investment indivisibility associated with distribution networks means it will be less costly to expand an existing network, than to construct a new network. While an incumbent distributor might have to replace existing pipelines with larger diameter piping or piping capable of operating at higher pressures, it might not have to incur other costs which a new investor would, such as installing pressure reducing stations.

Unlike the transmission sector, foundation contracts are generally not used to underwrite distribution networks. The opportunity to reduce some risks associated with sunk costs by signing these contracts is thus not readily available. The Tasmanian Government noted the uncertainty facing a new distributor when establishing a customer base:

In a greenfield gas market, a developer is required to make a significant upfront investment in the construction of the network with little certainty regarding customer penetration. Revenues that would make such investments viable only begin to accumulate in a significant way after a number of years. (sub. 45, p. 6)

Given the large sunk costs and the high risk that a potential entrant would be unsuccessful, the barriers to entry for distribution networks tend to be high, especially where a network services a large proportion of small users (such as residential users).

However, the OECD (2000) argued that competition between networks could emerge (and thus there is some contestability) where there are a number of large users in a small geographical area. In addition, a distribution system is not protected from competition (for large users) from spur lines running off a transmission pipeline or a neighbouring distribution network, as noted by ENERGEX and Allgas Energy:

… we have a transmission pipeline running through the middle of our network, so you actually find that's another countervailing power with our large customers because they can just go, 'Oh, we'll just build our own pipes and transmission; it's just one kilometre down there'. So that's another force that means we always have to be supplying them at the best price we can give them. (trans., p. 310)

Competition for new development

Competition over the right to build a new network can also limit a network owner's ability to exert market power and earn monopoly profits. This could happen, for example, through a local government conducting a competitive tender process that locks in prices for users before the development of the network. However, the Commission is aware of only one distribution network (Mildura distribution network) that has been constructed after completion of a tender process since 1997 (Australian Gas Association, sub. 13, p. 63). This might indicate that potential new network developments are often marginal in nature.

Other forces that constrain market power

Other forces (exogenous to the distribution network sector) might constrain the ability of a network owner to exercise market power, including:

- the bargaining power of users
- the price elasticity of demand for distribution network services.

In circumstances where market power is constrained, a service provider faces commercial incentives to operate efficiently by focusing on increasing throughput.

Bargaining power of users

The bargaining power of users might constrain the market power of distribution network owners. On a network where a large proportion of gas is used by large industrial customers, the bargaining power of these customers is relatively significant, especially when they have substitution possibilities such as building a spur line from a transmission pipeline.

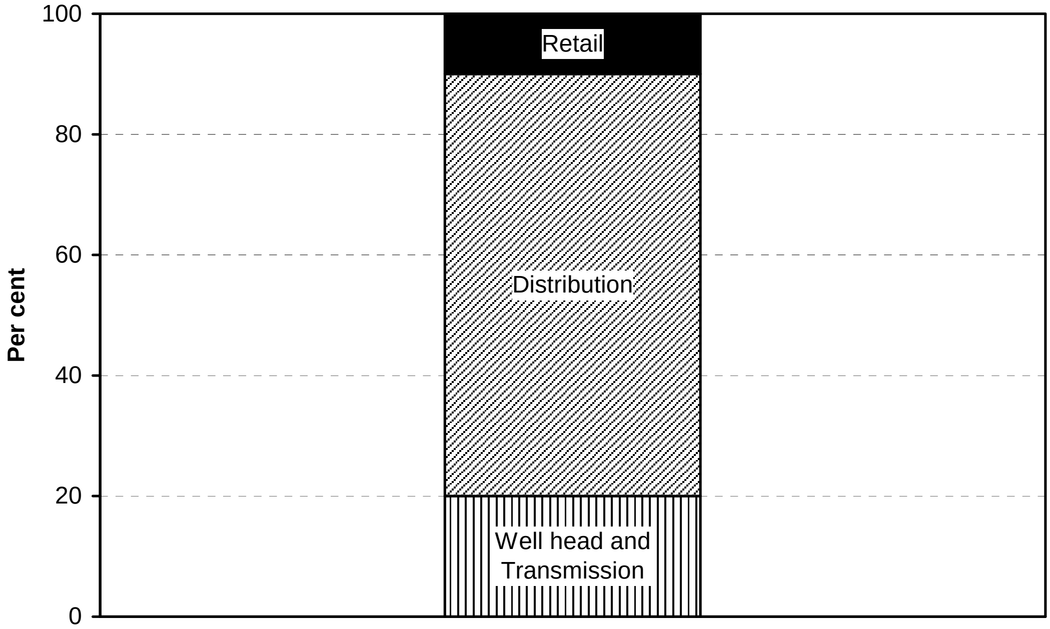
In addition, retailers that contract with distributors and on-sell to residential users might have some bargaining power relative to distributors. This power arises because many retailers of natural gas are also retailers of other fuels and energy sources (particularly electricity). If they cannot pass on natural gas distribution price increases to end users because demand is elastic or retail prices are regulated, and retail margins are lowered, then they might have an incentive to promote other fuels:

> The primary objective of retailers is to maximise margin on a range of products and services, which includes electricity as well as gas. Retailers are more interested in marketing a brand to entice consumers from other retailers rather than increasing utilisation of a network that will result in price reductions for customers (and other retailers' customers) in the longer term. (Envestra, sub. 22, p. 21)

> … decline in retail margins has a direct impact on Envestra. Because the retailer's margin on natural gas is reduced, it is more likely to promote other fuels with its new customers than natural gas. This again reduces network utilisation in Queensland and in the longer term will increase network prices to users of the network. If this trend continues, natural gas will soon not be viable in Queensland. (Envestra, sub. 22, p. 15)

There appears to be less incentive for natural gas retailers to increase the penetration of natural gas because retail margins are relatively low (with retail costs and margins at around 5–10 per cent of the final gas price) (figure 2.6). Origin Energy (sub. 52, p. 3) argued that regulation of retail prices and its interaction via the Gas Code has led to 'a lowering of retail margins and incentive to innovate'.

Figure 2.6 **Composition of residential natural gas costs**



Source: Envestra, pers. comm., 20 August 2003.

Alinta/Multinet noted circumstances in which the bargaining power of users in the distribution sector might be observed:

- independent retailers attached to distributors could provide a countervailing power to monopoly price increase, especially if they were price capped;
- distribution prices flow through retailers and to final customers, all of whom can monitor and object to price increases and produce a countervailing power to monopoly prices; and
- even with an associated retailer a distributor would be constrained from increasing prices by larger customers, industry associations, lobby groups and the media. (sub. 36, p. 21)

Price elasticity of demand

As noted, price elasticities indicate a service provider's ability to exert market power. A service provider facing a low price elasticity of demand for distribution services has greater ability to exert market power because it can increase its price without revenues falling. Typically, elasticity of demand is higher in the long run.

The demand for distribution services is directly related to the demand for natural gas. In the commercial and industrial sectors, the demand for distribution services (as with transmission services) is a 'derived' demand. The four factors that influence the elasticity of demand in the transmission sector — (1) the elasticity of demand for final products, (2) the proportion of the final product's total costs that the service comprises, (3) the availability of substitutes for the service and (4) the elasticity of supply of other input providers — thus apply in this sector too (so are not discussed again here).

In the residential sector, the demand for distribution services is akin to demand for a consumption good. The price elasticity of demand is thus mainly influenced by:

- the proportion of consumers' income spent on the consumption good
- the availability of substitutes (Sloman and Norris 1999).

Residential customers use natural gas predominately for space heating, water heating and cooking. This extent to which customers use gas for particular purposes varies around Australia. In warmer climates, for example, gas is used less for space heating as consumers are more likely to use alternatives such as electric reverse cycle air conditioning.

Proportion of consumers' income

The larger the proportion of consumers' income spent on a good, the more elastic is the demand. Even though the cost of distribution is around 70 per cent of the costs of supplying natural gas to residential users (figure 2.6), it appears to account for a relatively small share of consumers' income. In 1998-99, the proportion of consumers' expenditure (not income) spent on domestic fuel and power was 2.6 per cent (ABS 2000). This proportion will vary by State and Territory. In Victoria, consumers are likely to spend a more significant proportion of their income on natural gas consumption (due to the cold weather) and, therefore, will be more sensitive than users in warmer States, such as Queensland, to a price change.

While the proportion of consumers' income spent on natural gas distribution might be relatively small, the effect on the elasticity of demand can be overshadowed by the availability of close substitutes (see below).

Availability of fuel and energy substitutes

The extent to which fuel and energy substitutes exert competitive pressure on the distribution sector depends on the ease with which a consumer can replace natural gas with another fuel or energy source for a particular purpose, and on the substitute's price relative to the price of natural gas. Residential users can readily replace natural gas (especially in the long run) with:

- electricity, wood and LPG — for space heating
- electricity, LPG and solar power — for water heating
- electricity and LPG — for cooking.

Relative prices thus play an important role in determining the extent to which these substitute fuels and energy sources exert competitive pressure.

Electricity is an important competitor to natural gas. The competitive pressure exerted by electricity off-peak tariffs is particularly significant:

> … gas competes with electricity, in particular with the electricity-heating tariff, which is generally relatively low as it is off peak. (Alinta/Multinet, sub. 36, p. 20)
>
> Substitutability between gas and electricity is quite high. Maybe 7 to 10 per cent of consumers change their energy source at any particular point in time. Certainly if a gas distributor can't hook up two services, which is heating and cooking, then it's probably not economic to connect a gas distributor, that is. So gas distributors compete against the electricity hot water tariff and that tends to be low peak and relatively low so if you can't get substantially under that electricity hot water tariff then you probably won't be successful in getting a customer. (Alinta/Multinet, trans., p. 201)

The competitive pressure exerted by electricity is ongoing, because although individual customers might be locked into using a natural gas appliance for around 10–15 years, around 7 per cent of consumers change appliances every year:

> Customers can make decisions regarding substitute products when selecting or updating their capital equipment or appliances. This is particularly the case with new extensions where households are choosing their energy source and can tradeoff costs and benefits of alternative sources of energy.
>
> At any time this may affect some 7 per cent of consumers who are new households or are replacing equipment and may provide some constraint on the exercise of market power in electricity or gas pricing. (Alinta/Multinet, sub. 36, p. 20)

Electricity has a number of advantages over natural gas. While electricity can be used in all the purposes for which gas is used, gas cannot always replace electricity (for example, a computer cannot run on gas). The market penetration of electricity is nearly 100 per cent, meaning significant economies of density can be exploited in this sector. Envestra noted some of the advantages of electricity over gas:

- gas is a fuel of choice that is not automatically provided to all properties;
- unlike electricity, gas must be reticulated in new subdivisions at the cost of the network owner;
- gas appliances and installation are generally more expensive than their electrical counterparts;
- arranging gas connection and appliance installation is more complex (for example, fluing is normally required indoors in contrast to electrical appliances that can be plugged into a power point); and
- there are a greater range of electrical appliances (and electrical retailers) available. (sub. 22, p. 20)

For natural gas distributors attempting to penetrate a new market, the competitive pressure exerted by substitute fuels and electricity is particularly significant:

> Prices will largely be determined by competition from competing fuel sources within the Tasmanian energy market. The key principle underlying government policy in relation to gas distribution is that the distribution of natural gas is dependent on the successful sale of gas to consumers. In this regard, natural gas is simply one energy source within the competitive energy market, competing against other forms of energy such as electricity, coal, fuel oil, LPG and wood. Therefore, it will be necessary for gas distribution access charges to be competitive within this energy market. In this environment, the gas distributor will not have market power within the overall energy market, even where it has an exclusive right to distribute natural gas, due to competitive pressure from other energy sources. (House of Assembly, Parliament of Tasmania, 29 May 2003, cited in ACCC, sub. 48, p. 20)

Differences across States and Territories

The extent to which market power is constrained for a distribution network will differ according to the number and type of users of that network. The number and type of users varies across networks (table 2.9). In Queensland, where the number of users of the distribution networks is relatively low:

- the reliance on large industrial or commercial customers is significant
- the unit price of gas is higher.

The market power of distributors in Queensland might be considerably constrained, therefore, by the bargaining power of users and the competitive pressure exerted from other fuel and energy sources (Allgas Energy, sub. 25, p. 13). In contrast, in Victoria — where the number of users of the distribution network is relatively high and a significant proportion of the natural gas transported in the distribution network goes to small residential customers (table 2.9) — the bargaining power of users and the competitive pressure exerted by other fuels might not have as significant an impact on the market power of distributors.

Table 2.9 **Users of distribution networks in Australia, 2001-02**

Network	*End users*[a]	*Gas consumed by residential users*	*Average consumption per residential user*	*Average consumption per commercial and industrial user*
	no.	% of total	GJ	GJ
New South Wales	901 172	22	26	2 280
Victoria	1 527 123	53	63	1 798
Queensland	145 412	13	20	2 883
South Australia	345 436	26	32	3 787
Western Australia	458 276	10	20	11 183
ACT	88 711	63	49	1 147
Northern Territory	916	2	81	28 827

[a] Includes residential, commercial and industrial users.

Sources: PC estimates; AGA 2003.

FINDING 2.2

Distribution networks have natural monopoly characteristics. The scope for distribution network owners to exercise market power arising from such characteristics can be constrained by a number of factors, including the availability of other fuel and energy substitutes. The extent to which market power is constrained differs across networks. A network owner servicing a new market (or one in which use is low) generally has little market power.

2.5 Emerging competition

In the early 1990s, Australian governments agreed to two major energy market reforms: an agreement to create a national electricity market and an agreement to reform the gas industry through arrangements that would ensure national free trade in natural gas. Until 1995, when the reforms were incorporated into the National Competition Policy agreements and assessment process, progress towards national free trade in natural gas was limited (NCC 2002b).

Some publicly owned gas businesses across States in 1994-95 underwent restructuring, often with a view to privatisation. Some States also introduced State-based access regimes for gas pipelines (NCC 2002b). In 1995, the intergovernmental Gas Reform Task Force was established to develop a uniform national access code for gas pipelines and in 1997 Australian governments agreed on the implementation of the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code).

Reforms since 1995, to encourage competition in gas production and retail, have included:

- reforms to upstream regulatory arrangements, such as acreage management
- movement towards full retail contestability in most jurisdictions.

As a result of these reforms, the gas market has changed significantly since the development of the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime), to become more competitive. A number of participants noted the role of the reforms in these changes:

> … the evidence to date is that gas policy reform under NCP [National Competition Policy] has already generated substantial activity in the development of new gas production and gas pipelines. Current policy settings have created the environment for effective competition in gas markets. (NCC, sub. 57, p. 6)

> … we believe that it is demonstrable that the whole process of gas market reform, including the [Gas] Code, has led to a more dynamic and competitive upstream and downstream gas industry. We believe that it has led to greater diversification of supply sources and to greater consumer choice. (Australian Petroleum Production and Exploration Association, trans., pp. 356–7)

These reforms and gas market changes have impacted on both the transmission pipeline and distribution network sectors.

Transmission pipeline sector

When the Gas Access Regime was developed, there was limited interconnectivity between gas fields and markets. Generally, a market was supplied by only one field. ExxonMobil noted that, in this environment, the regime was understandably heavy handed:

> The Gas Access Regime was developed at a time when the market history was one of very limited interconnectivity between State transmission systems, supply basins and markets, and when transmission and downstream activities were primarily monopoly franchise activities in each State. In this environment the form of the Gas Access Regime was understandably, if not necessarily, heavy handed as it endeavoured to facilitate the rapid development of a transnational pipeline grid to support enhanced upstream and downstream competition. (sub. 8, p. 2)

However, over the past several years, there has been a significant movement towards interconnectivity:

> While there is scope for further pipeline development before a fully integrated national grid is realised, the significant and rapid change in the market over the past several years now demonstrates clearly a strong momentum towards deepening competition and interconnectivity. For example, downstream market restructuring and pipeline

> access has brought about the emergence of a number of new and planned gas supply projects. (ExxonMobil, sub. 8, pp. 2–3)

> New pipelines have been built, new interlinkages have been made. It is no longer [only] one pipeline into Sydney … [or] Melbourne. It will, in the very short term, no longer be one pipeline into Adelaide. I think the whole nature of the eastern seaboard market has changed quite dramatically. (Australian Petroleum Production and Exploration Association, trans., p. 362)

Interconnection has led to the development of a transmission network in the eastern States' gas market. The removal of restrictions on interstate sales of gas was one key reason for the growth in interconnectivity, as noted by the ACCC:

> Removal of restrictions on interstate sales of gas, coupled with the introduction of third party access to natural gas transmission and distribution pipelines has encouraged the construction of a number of new pipelines. These pipelines bring new sources of supply to markets, both connecting existing producing basins to new markets and more recently bringing new basins on stream. (sub. 48, p. vi)

Benefits of interconnection

Development of network interconnection in transmission can provide a number of benefits. First, increased interconnection plays a crucial role in facilitating competition in upstream and downstream markets. Joskow (2003) noted the importance of transmission in electricity markets:

> Transmission networks provide the essential supporting platform upon which competitive wholesale markets depend … A well functioning transmission network is a critical component of a program to create robust competitive wholesale and retail markets for electricity. (Joskow 2003, p. 68)

Similarly, Viscusi, Vernon and Harrington (2000) noted the role of the well-developed US gas transmission network linking buyers and sellers and facilitating a more dynamic and competitive gas market:

> Where pipelines pass close to one another, links have been added so that those pipelines can provide transportation services to an expanded array of producers and customers. This structural change has linked more buyers (local distribution systems and large customers like manufacturers) and sellers (producers of natural gas), and the ability of buyers and sellers to engage in direct transactions has spawned more efficiency contractual arrangements. The evidence is that the result has been a more competitive and more efficient market for natural gas. (Viscusi, Vernon and Harrington 2000, p. 631)

Second, greater interconnection (with third party access) can reduce entry barriers for gas suppliers and increase the contestability of the market. De Vany and Walls

(1995) noted that trade in interruptible transmission capacity can lower suppliers' entry and exit barriers:

> A supplier who wishes to contest a market need not construct a new pipeline to do it, and so they no longer are faced with high fixed costs of entering and exiting markets. Thus, the 'hit and run' entry of contestable markets theory has been put in place in gas markets by allowing gas and interruptible transportation to be actively traded among a variety of participants.
>
> Buyers and sellers of gas in every market compete throughout the network. Suppliers can contest any market to which they can deliver gas at a competitive price, and gas can flow across the network to eliminate price disparities. Even those markets served by only one pipeline have available to them sources of supply from a wide network. (De Vany and Walls 1995, p. 106)

This contestability (threat of competitive entry) can act as a restraining factor on the dominant supplier. Some electricity market studies support this view:

> One of the most straightforward, and probably economic, ways of promoting competition would be to increase the contestability of separate geographic markets by beefing up the transmission infrastructure that serves them. With sufficient transmission capacity, attempts to raise prices in smaller regions become unprofitable because such attempts simply draw supply from neighbouring regions. In fact, adding transmission capacity can actually decrease its use: the threat of competitive imports can be sufficiency to forestall the exercise of market power. (Borenstein and Bushnell 2000, p. 51)

In addition, connecting gas to a new market can increase the competitive pressure on existing energy sources (such as electricity and LPG), reducing overall energy costs.

Third, interconnection can improve allocative efficiency by enabling gas to be transported to where it is valued the most highly (Dalziell, Noble and Ofei-Mesah 1993).

As suppliers exploit price differences across markets (arbitrage opportunities), prices can converge (box 2.2). De Vany (1996) noted:

> By allowing the disconnected pipeline network that was inherited from regulation to become more strongly connected, open access enlisted the power of networks to discipline markets. Because transportation could be used to link markets, interconnections integrated separate pipelines into a network. Imbedding separate markets in a network of more strongly connected links puts buyers and sellers in connection with more alternatives, expanding competition by a power of the number of new links. This is evident from the way in which prices converged as more pipelines opted to open their systems to transportation. (De Vany 1996, pp. 215–16).
>
> Improved interconnection of the gas transmission network will be an important factor in enhancing flexibility and security. It can allow additional gas to be transported in the

short term from one market to a nearby one — for example, when extreme weather in one market coincides with mild weather in another. (IEA 2002d, p. 17)

Box 2.2 **Development of networks**

Networks connect geographically separated markets or users and develop through the connection of additional markets or users.

Networks can develop because of price differences across geographically separated markets that enable arbitrage opportunities. An arbitrage opportunity arises if a product's demand price in market A is higher than its supply price in market B plus the costs of transporting it from market B to A (Nagurney 1993). As suppliers in market B respond to this opportunity by supplying to market A, the supply price in market B will rise (as supply decreases) and the demand price in market A will fall (as supply increases).

As a network develops, competition between suppliers of goods in previously isolated markets emerges. As suppliers exploit arbitrage opportunities, the prices in these markets tend to converge. The rate at which prices converge depends on the nature of pre-existing contracts with suppliers. That is, the length of time until existing contracts expire. The extent to which prices converge indicates the extent to which the markets are connected and can therefore be defined as one market (Doane and Spulber 1994; Chattopadhyny and Costello 2002; De Vany and Walls 1995). Under the 'law of one price' a market is defined as 'the area within which the price of a good tends to uniformity, allowances being made for transportation costs' (Stigler and Sherwin 1985, p. 555).

Networks tend to grow in scope and complexity over time (Lyon and Hackett 1993). Greater network complexity can also mean more numerous network transactions and higher transaction costs. More sophisticated markets arrangements often emerge to reduce these transaction costs, such as the use of intermediate brokers and development of spot markets (Short, Heaney and Burns 2003).

As a network becomes more complex, competition can become more dynamic in nature and the market will tend not to maintain a static equilibrium. Even small investments can connect previously unconnected markets. In a connected network with open access and liquid transportation markets, suppliers can enter a market without making irreversible decisions — constructing new network infrastructure or entering long-term contracts — by purchasing short-term or interruptible transportation services (De Vany and Walls 1995).

Where competition is more dynamic in nature, it is difficult to assess the causes and consequences of market power. In a dynamic market, even supranormal profit plays a socially productive role as it signals when investment or innovation is needed (Ellig and Lim 2000). It is also difficult to regulate effectively and the social costs of distorting the market selection process can be high.

Fourth, interconnection can enhance security of gas supply. Where there is an explosion at a gas production facility that limits supply from a particular basin, for example, users can gain access to other supply sources. Interconnection can also enhance flexibility of supply to deal with variations in demand, such as seasonal demand differences across regions, and unforseen changes in demand (for example, due to a short-term extreme variation in temperature). The International Energy Agency (2002d) noted:

Interconnection in Australia

As the gas transmission network in Australia has developed, many of the benefits of interconnection have been realised. The gas market is more competitive, in particular, previous market boundaries are being eroded:

- Users of natural gas can now be supplied from a number of basins — AGL, for example, has signed contracts for the supply of gas from the Gippsland, Cooper–Eromanga and Surat–Bowen basins to meet its future gas requirements in New South Wales, Victoria, the ACT and South Australia (AGL 2002).
- Suppliers of natural gas can now sell into a number of end use markets — gas from the Cooper basin, for example, can be sold into the New South Wales, Victorian and South Australian markets.

As the interconnectivity of the transmission network has grown, the dynamic nature of, and the market opportunities in, the sector have also increased. Even relatively small investments can significantly change the level of competition and how gas moves between supply sources and end markets. The impact of more recent and potential investments was noted in the Minister's recent decision (Macfarlane 2003a) to revoke coverage of parts of the Moomba–Sydney pipeline:

> Gas pipeline investments in south-east Australia have seen the commissioning of the EGP [Eastern Gas Pipeline], the construction of the joint venture SEA [South East Australia] Gas Pipeline, the establishment of the Victorian gas hub and the construction of the Tasmanian Gas Pipeline. Together with an increase in pipeline capacity, these investments have enhanced the ability to offer physical and financial swap and other hedging contracts across several pipeline systems … (Macfarlane 2003a, para. 21)
>
> Consideration is also being given to the construction of a Ballera–Moomba sales gas pipeline to better integrate the Queensland and NSW markets. Such upstream market developments are indicative of an increasing degree of inter basin transfers and interpipeline competition, and highlight the fundamentally different character of the emerging gas pipeline network. (Macfarlane 2003a, para. 26)
>
> North bound capacity of the Interconnect can be matched to that south bound without duplication or looping, simply by addressing the compression limits at Wollert. This would provide equivalent transmission services to Victorian gas suppliers seeking to compete for both Sydney and regional NSW centres. (Macfarlane 2003a, para. 66)

The effect these changes can have on the market for transmission services was also noted by the Minister:

> A Moomba to Sydney gas transmission service in future may be contracted for via the Moomba–Adelaide pipeline system (MAPS) and SEA [South East Australia] Gas pipelines and either of the Interconnect or the EGP [Eastern Gas Pipeline] … It is therefore no longer appropriate to think in terms of gas transportation as being only from a single well head or processing plant along a single transmission pipeline to a single offtake point. (Macfarlane 2003a, para. 24)

The recent gas swap between Origin Energy Retail and a number of Cooper basin producers also demonstrates the more dynamic nature of the gas market in Australia. Santos (2004) noted the details of this swap:

> Origin [Energy Retail] has agreed to deliver gas produced in its central Queensland fields to the producers at Roma in Queensland. The producers will then use this gas to meet part of their customer requirements in south-east Queensland. In return for the gas from Origin, the producers will redirect (swap) an equal quantity of Cooper basin produced gas to Origin at the Moomba gas hub … Having access to swapped gas at the Moomba gas hub eliminates the need for Origin to construct major additional pipeline infrastructure in the short term. (Santos 2004, p. 1)

The growth of the Australian transmission network has also enhanced flexibility and security of gas supply. This was illustrated by the events following a fire at the Santos gas plant at Moomba in January 2004. This fire significantly reduced gas supplies from Moomba to its markets, including Adelaide and Sydney. However, the availability of gas from two competing pipelines, the Eastern Gas Pipeline (which supplies gas from Victoria to Sydney) and the recently completed South East Australia Gas Pipeline (which supplies gas from Victoria to Adelaide) reduced the impact on supply to these two markets. Howarth (2004) noted:

> Cool weather and the growing grid of high pressure pipelines across Australia have saved New South Wales and South Australia from crippling natural gas shortages from the fire at Moomba gas plant on New Year's Day … [both states were] spared the worst impact of the Moomba fire because new gas pipelines into both states from Victoria were able to deliver alternative gas supply … (Howarth 2004, p. 73)

Distribution networks in Australia

The more competitive nature of the energy market as a result of reforms is likely to have increased the competitive pressure on the distribution network sector since the development of the Gas Access Regime.

Under energy market reforms, the electricity sector underwent changes aimed at minimising the costs of delivered electricity to consumers, both large and small, and improving the efficiency of both electricity pricing and investment in new electricity infrastructure (ABARE 2003). Short et al. (2001) noted how these reforms have increased the efficiency of the electricity sector, and reduced the price of electricity:

> The Australian electricity sector has undergone significant reform that has lead to a significant reduction in the cost of electricity supply compared with previously state based, state owned monopoly structure … It is apparent that following the introduction of markets where generators compete to sell electricity (the NEM [national electricity market] and its predecessor), the prices paid for wholesale electricity fell significantly when compared with previous cost of service arrangements. (Short et al. 2001, pp. 89 and 82)

The increased competitiveness of the electricity sector has potentially placed pressure on the gas market to be more competitive. In particular, this impacts on distribution networks that supply household users:

> With gas, electricity is almost always a dominant competitor at the household and business users level and this itself places pressure on gas suppliers to perform efficiently, the more so since electricity industry reform. (Institute of Public Affairs, sub. 2, p. 23)

Other reforms that have potentially placed greater competitive pressure on distribution networks include:

- separation of ownership of the gas and electricity distribution networks in Western Australia, so that the owner of the gas network (Alinta Gas Networks) is competing with the owner of the electricity network (Western Power) to increase the utilisation of its network
- separation and privatisation of the gas distribution network in Melbourne, so there are three separate sections and owners (TXU Networks, Envestra and Multinet Gas Networks).

Future developments

A number of factors have the potential to make the future gas market environment even more dynamic and competitive:

- The demand for natural gas is forecast by ABARE analysts to increase strongly — by 3.8 per cent per year to 2019-20 (Dickson and Noble 2003).
- The consumption of natural gas in the eastern Australian States is projected by ABARE analysts to outstrip production in these States by 2012 (a projection that includes the forecast production from new coal seam methane fields) (Dickson and Noble 2003).
- The major reserves of natural gas are located in the north west of Australia.

These factors mean that the major future supplies of natural gas will be from gas fields that are further away from a large proportion of the market. The costs of delivering gas will thus be higher (for this portion of the market) and all segments of the supply chain will be under greater pressure to ensure gas reaches these markets at competitive prices. Greater connectivity will arise as new supply sources are fed into parts of the existing network.

There is also scope to extend gas distribution networks into currently unserviced markets:

> There is also much scope for extension of gas distribution networks into areas not currently served (unlike electricity, gas is not regarded as an 'essential service' in all markets and is not available in many towns, suburbs and streets, even in the capital cities). (Energy Retailers Association of Australia, sub. 9, p. 1)

As noted, natural gas entering previously unserviced markets has to compete vigorously with existing fuel and energy sources, especially electricity.

While the gas market has changed significantly since the Gas Access Regime was developed, it is still in transition. The Council of Australian Governments Energy Market Review, chaired by Warwick Parer noted:

> The recent gas reforms have been effective. By facilitating access to pipelines, and removing the previous restrictions on interstate trade in gas, new pipelines have and are being built, new fields have been discovered, and some initial upstream gas competition has been introduced. (EMR 2002, p. 35)
>
> Nevertheless, Australia's eastern gas markets can still at best be described as emerging. While these recent developments are encouraging, Australia's gas markets remain immature — particularly when compared with the gas markets in the United Kingdom or United States of America. The degree of supply competition in Australia's eastern markets is still weak — particularly compared to Western Australia. This is reflected in lower gas prices in Western Australia. (EMR 2002, p. 190)

A number of inquiry participants endorsed this assessment of the gas market. The ACCC noted that while the reform objectives are being attained, upstream and downstream competition is still emerging:

> By and large, the evidence so far is that [gas reform] objectives are being attained. Investment in the industry has increased substantially. Gas consumption has grown at a higher rate than previously was the case. New pipelines are bringing alternative supplies to gas markets. Upstream and downstream competition is emerging, with some way to go. There has been a reduction in published pipeline tariffs and listed gas transmission businesses have met with investor acceptance. Again I simply reiterate, this is the early days in gas reform in Australia and we expect these benefits to increase and accelerate. (trans., p. 322)

WMC Resources expressed similar sentiments:

> WMC [Resources] sees that, particularly in Western Australia, upstream competition is developing. Overall, WMC [Resources] would not, however, regard gas markets as effectively competitive nor does it believe that such competition will continue if open access to transmission pipelines is removed. The description, in the Parer [EMR 2002] report of eastern gas markets as 'emerging' is an accurate assessment. (sub. 43, p. 34)

The Essential Services Commission noted that there is greater contestability in the transmission sector than in the distribution sector:

> Market developments in Australia have increased the contestability of gas transmission services. Investments in gas transmission infrastructure have led to progressive interconnection of gas basins and gas markets. This has, in turn, increased gas-on-gas and pipeline-on-pipeline competition. Market participants now have more choice and negotiating power over the terms of their bulk gas supplies (commodity plus transmission costs). This type of contestability, with rare exceptions, does not exist in gas distribution. (sub. DR112, p. 12)

The challenge is to design a gas access regime that accommodates and supports the emergence of competition and imposes regulatory intervention only where it can generate significant improvements in economic efficiency.

FINDING 2.3

The market conditions facing the gas transmission and distribution sectors have changed since the Gas Access Regime was developed. In the transmission sector participants are increasingly having to respond to new opportunities that arise in an emerging competitive market. Competition in this sector is expected to increase further through even greater connectivity. The gas distribution sector is also facing more competitive market conditions arising, in particular, from a more competitive electricity sector. Notwithstanding these changes, the gas market is still in transition. In this environment, some form of a gas access regime is still warranted.

3 Gas Access Regime

The National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) is an industry-specific regime that is given legislative effect in a Gas Pipelines Access Act in each State and Territory. The legislation implements the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code). The Gas Access Regime exists alongside, and interacts with, the national access regime operating for all essential services in Australia, as contained in part IIIA of the *Trade Practices Act 1974* (the TPA). The Minister certifies industry-specific access regimes under part IIIA (to establish that the regime is consistent with the Competition Principles Agreement).

The history of the Gas Access Regime, the elements of the regime and how the regime meshes with other relevant regulatory requirements are discussed in this chapter.

3.1 History of the Gas Access Regime

Until recently, much of Australia’s natural gas supply chain was highly integrated with government ownership of natural gas sector assets. Legislative and regulatory barriers restricted interconnection of the States’ pipeline systems and thereby restricted interstate trade in natural gas. Government reforms in the gas industry began in 1991 and, following the report of the Hilmer Committee (1993), were rolled into the broader National Competition Policy program.

Developments in the early 1990s

Governments have always been heavily involved in the gas industry in Australia, but the nature of the regulation has changed over the past 15 years. First, regulation now particularly focuses on competition issues (in addition to safety, technical standards, licensing requirements, royalties and pricing). Second, Australian, State and Territory governments have adopted a more systematic and nationally-consistent framework.

The change in policy focus was initiated through the development of the National Strategy for the Gas Industry in 1991. The Australian Government drafted this strategy (DPIE 1991) after canvassing options for developing a national strategy for the natural gas industry, concentrating on issues associated with pipeline regulation and the role of the States and Territories.

Subsequently, the Council of Australian Governments (COAG) took responsibility for gas reform. At meetings in 1992, 1993 and 1994, COAG considered the need to remove impediments to free and fair trade in gas. At the 1994 COAG meeting, all governments agreed to take steps to stimulate competition and achieve ‘free and fair trade in natural gas’. This agreement had three goals:

- to remove policy and regulatory impediments to competition in the natural gas sector
- to remove restrictions on interstate trade in natural gas
- to develop a nationally integrated and competitive natural gas market by establishing a national regulatory scheme for third party access to natural gas pipelines and thereby facilitate investment in exploration and development, and the interconnection of gas pipelines (National Gas Pipelines Advisory Committee 2000).

COAG agreed to reform in a number of areas to achieve free and fair trade in gas (box 3.1), including removing legislative and regulatory barriers to inter- and intra-jurisdictional trade in gas and requiring vertical separation (ring fencing) of transmission and distribution businesses from other related businesses.

Following the COAG agreement, several jurisdictions introduced legislation and other arrangements to implement the uniform national framework:

- The *Moomba–Sydney System Sale Act 1994* (Cwlth) implemented an access regime and ring fencing arrangements to facilitate the sale of the Moomba–Sydney pipeline.
- The *Natural Gas Pipelines Access Act 1995* (South Australia) implemented an access regime and ring fencing arrangements for pipelines licensed in South Australia, along with measures to facilitate the sale of the Moomba–Sydney pipeline.
- The *Petroleum Amendment Act 1995* (Queensland) implemented an access regime and ring fencing arrangements for pipelines licensed in Queensland and facilitated the construction of the Ballera–Wallumbilla and Ballera–Mount Isa pipelines, and the sale of the State Gas Pipeline.
- The *Goldfields Gas Pipeline Agreement Act 1994* (Western Australia) implemented an access regime and ring fencing arrangements to facilitate construction of the proposed Goldfields Gas Pipeline.

- The *Gas Corporation Act 1994* (Western Australia) and Gas Transmission Regulations 1995 implemented an access regime and ring fencing arrangements for the Dampier–Bunbury pipeline.
- The *Gas Act 1996* (New South Wales) including the Third Party Access Code for Natural Gas Distribution Networks in New South Wales established an interim access code for distribution in that State.
- The Victorian Access Code implemented an access regime for pipelines in Victoria.

Box 3.1 **Summary of the 1994 COAG agreement on free and fair trade in gas**

In relation to free and fair trade in gas COAG broadly:

1. agreed to remove legislative and regulatory barriers to inter- and intra-jurisdictional trade in gas
2. agreed to implement complementary third party access legislation
3. noted that third party access legislation should be developed cooperatively across jurisdictions
4. noted that legislation arising from the Hilmer report would apply to gas pipelines
5. agreed to adopt uniform national pipeline construction standards
6. agreed not to issue further open ended franchises and to implement more competitive franchise arrangements
7. agreed to price control and maintenance in the gas industry being considered in the context of the National Competition Policy
8. noted that contracts between producers and consumers entered into before the enactment of gas reform legislation would not be overturned by that legislation
9. agreed to corporatisation of gas utilities
10. agreed to the vertical separation of publicly owned transmission and distribution businesses and to introduce legislation to ring fence these businesses in the private sector
11. agreed that reforms to the gas industry be viewed as a package
12. noted that reforms should not restrict the use of natural gas (for electricity generation, for example).

Source: COAG 1994, p. 5 and attachment B.

Some States and Territories placed caveats on participation in the reform process. In Victoria, several aspects of the COAG agreement in 1994 were subject to the resolution of issues in applying the petroleum resource rent tax in the Gippsland

Basin (Office of State Owned Enterprises 1994, p. 15). The Government of Queensland also placed caveats on the reforms, including the requirement that satisfactory arrangements be made with gas producers in Queensland to overcome possible gas shortages for southern and central Queensland (IC 1995a, pp. 56–7).

National Competition Policy

The report on National Competition Policy completed in August 1993 (Hilmer Committee 1993) was an important influence on gas access reform. The report sought to promote a nationally consistent approach to competition policy and considered six broad issues:

- part IV of the TPA (anticompetitive provisions)
- restrictions imposed by States and Territories
- the structural reform of public monopolies
- third party access to essential infrastructure
- responses to monopoly pricing issues
- competitive neutrality.

In relation to third party access to essential facilities, the Hilmer Committee (1993) proposed a new legal regime under which businesses can be given a right of access to essential facilities when the provision of such a right meets certain public interest criteria. The regime proposed was general in nature applying to access pricing and related issues in designated essential facilities irrespective of ownership. The Hilmer Committee noted that third party access was only part of a package of competition reforms and it expressed a preference for structural reform as the policy to deal with vertically integrated businesses' denial of access.

In proposing a generic regime, the Hilmer Committee (1993) noted the existence of industry-specific legislation such as the *Telecommunications Act 1991* (Cwlth) and the *Petroleum Pipelines Act 1969* (Western Australia), as well as proposed industry-specific legislation for gas and electricity arrangements. However, it considered that access legislation was not needed on an industry-specific basis, given important similarities for access and related issues across key infrastructure industries and because it permits expertise and insights gained in access issues in one sector to be more readily applied to analogous issues in other sectors (Hilmer Committee 1993, pp. 248–9).

Following the report of the Hilmer Committee (1993), COAG agreed to a comprehensive package of reforms in three agreements in April 1995 (box 3.2), encompassing:

- a legislated access regime, providing third party access to certain facilities that are essential for competition, along with other provisions
- an agreement to review legislation that restricts competition (and reforming regulation that restricts competition, where the restrictions on competition are not in the public interest)
- an agreement on competitive neutrality (fostering competitive neutrality between government and private businesses where they compete)
- reforms of government business enterprises
- an extension of part IV of the TPA
- the structural reform of monopolies (reforming the structure of public monopolies and implementing regulatory regimes to facilitate competition).

The National Competition Policy package provided for third party access to services of the significant infrastructure facilities through the national access regime (implemented in part IIIA of the TPA).

Box 3.2 **Elements of the 1995 National Competition Policy package**

The National Competition Policy package contained three intergovernmental agreements:

- The Competition Principles Agreement established agreed principles for the structural reform of public monopolies, competitive neutrality between the public and private sectors, the prices oversight of government enterprises, access to essential facilities and a review of legislation restricting competition.
- The Conduct Code Agreement set the basis for extending the coverage of the TPA to unincorporated businesses and government business enterprises. It set the consultative processes for modifying competition law and appointments to the Australian Competition and Consumer Commission. It also committed States and Territories to enact legislation giving effect to the Australian Government's new legislation.
- The Agreement to Implement the National Competition Policy and Related Reforms provided for payments by the Australian Government to State and Territory governments. These payments are made in return for the States and Territories meeting agreed obligations under the agreement and the Conduct Code Agreement, plus reform commitments in electricity, gas, water and road transport.

Source: IC 1995b, p. 3.

For the gas industry, COAG decided to implement industry-specific access legislation. In implementing industry-specific legislation, the Australian Government acknowledged that part IIIA of the TPA might be an alternative approach to such an industry-specific regime. It also noted, however, that a Gas Access Regime would enhance certainty, uniformity and consistency:

> Compared to relying on the part IIIA [of the TPA] regime, this approach will enhance certainty, uniformity and consistency — outcomes which will assist the expansion of the market for gas and encourage investment in pipelines. The scheme to be applied involves a balance between flexibility, required to deal with the individual circumstances of pipelines and customers, and a level of prescription to ensure consistency of treatment.
>
> … In the absence of a national approach (the do nothing approach), the alternative is to leave it to each pipeline owner to develop an access arrangement as a specific undertaking to be approved by the [Australian Competition and Consumer Commission], or for each jurisdiction to pass specific gas pipeline access legislation, Either course would result in a proliferation of differing regulatory arrangements with the potential to create 'rail gauge' problems, damaging development of a national market for gas, with adverse consequences for economic growth and Australia's international competitiveness A proliferation of individual regimes involving regulatory arrangements and institutions of varying quality was already occurring. (House of Representatives 1998, paras 32–3)

The Australian Competition and Consumer Commission (ACCC) noted:

> In setting up the Gas [Access] Regime, governments recognised that the developing nature of the gas industry warranted a more specific and certain approach than was available under the general access provisions. In part, the rationale for a specific gas regime was driven by the substantial degree of natural monopoly characteristics and market power that are present in gas pipelines connecting major basins and urban distribution systems in Australia. In the absence of a specific regime it was recognised that substantial elements of the industry would be subject to regulation under part IIIA [of the TPA] and so a decision was taken to streamline this process. (sub. 48, p. ix)

The ACCC also commented on the rationale for the differences in the type of regulation under the national access regime and the Gas Access Regime:

> The [Gas] Code has been developed to be a certified State-based regime under part IIIA [of the TPA] and to address the specific needs of the gas industry. It establishes a process that is more accessible to multiple access seekers than would operate under the generic provisions of part IIIA. It also requires access arrangements to meet criteria that are more specific to the needs of the industry than the criteria that would apply either to an undertaking or an arbitration determination under the generic provisions of part IIIA.
>
> The higher level of prescription employed in the Code is appropriate given the expectation that access would be facilitated for an increasing number of upstream and downstream parties. The prescription of access avoids high transaction costs as the number of access seekers increases. A higher level of prescription is also warranted in circumstances where the transmission price is a modest proportion of the final price

since access seekers would be unwilling to undertake a costly process in order to eliminate monopoly pricing.

Negotiate–arbitrate processes suffer a number of deficiencies in circumstances where the access provider possesses market power. In particular, they introduce incentives for the access provider to delay the process and adopt a ‘take it or leave it’ approach to negotiation. By contrast the Code provides a framework that facilitates commercial negotiation.

When the Code was being developed consideration was given to the adoption of a negotiate–arbitrate model. However, for similar reasons to those outlined above the Code developers considered that the reference tariff approach would be more effective than a negotiate–arbitrate model. (sub. 48, pp. ix–x)

Gas Code

COAG established the Gas Reform Task Force in mid-1995 to undertake a scoping study of gas reform and then, among other tasks, develop a comprehensive set of principles to be reflected in an access code. The task force released a draft version of the code, with an accompanying information paper, in August 1996. COAG subsequently established the Gas Reform Implementation Group to take over the work of the task force and finalise the access code. This group included representation from the Australian, State and Territory governments, the Australian Gas Association, the Australian Pipeline Industry Association, the Australian Petroleum Production and Exploration Association, the Business Council of Australia, the National Competition Council (NCC) and the ACCC.

The Prime Minister, Premiers and Chief Ministers approved the Gas Code through the COAG process in November 1997. Each jurisdiction signed the intergovernmental Natural Gas Pipeline Access Agreement, thereby agreeing to enact the Gas Code as a law of its State or Territory. In reaching agreement, some flexibility was granted to the States and Territories regarding institutional arrangements and transitional arrangements and derogations.

The 1997 intergovernmental agreement identified the objectives of the Gas Code as being to:

(a) facilitate the development and operation of a national market for natural gas;

(b) prevent abuse of monopoly power;

(c) promote a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders;

(d) provide rights of access to natural gas pipelines on conditions that are fair and reasonable for both service providers and users; and

(e) provide for resolution of disputes. (COAG 1997, p. 2)

3.2 The Gas Access Regime

Each jurisdiction gave legislative effect to the Gas Access Regime by enacting a Gas Pipelines Access Act. The legislation implements the Gas Code. South Australia developed the first Act (in 1997) to support the Gas Code. All States and Territories (except Western Australia) have since adopted the South Australian legislation. Western Australia has complementary legislation to support enactment of the Gas Code.

The Acts differ somewhat across jurisdictions, to deal with matters specific to a jurisdiction. The preliminaries of the Acts contain, for example, the identity of the regulator, the conferral of powers on Australian Government Ministers, bodies, local regulators and arbitrators, and derogations or transitional arrangements.

A Commonwealth Act facilitates national coverage. It applies to such areas as offshore waters and adjacent areas, as well as covering cross-boundary (interstate) pipelines. It also provides the basis for the powers of Australian Government bodies in the operation of the Gas Code.

The Gas Code is implemented on the basis of separating pipelines into those that are ‘covered’ and those that are not. Owners or operators of pipelines (service providers) that are not covered are not subject to any of the provisions in the Gas Code. Rather, they are subject to the general anticompetitive provisions of the TPA. An uncovered pipeline might become covered at a later stage through one of the coverage avenues (see below). Similarly, through the revocation process, a pipeline can move from being covered to uncovered.

Service providers of pipelines that are covered must comply with provisions in the Gas Code. They must submit access arrangements to the relevant regulator for approval, and comply with other provisions (such as ring fencing).

Figure 3.1 depicts the process to be followed by a third party user seeking access under the Gas Access Regime.

Coverage of pipelines

Under the Gas Code, a pipeline can become covered in one of four ways (figure 3.2):

- Governments could have listed the pipelines in schedule A of the Gas Code.
- Any person can apply to the NCC, requesting coverage.

- A service provider can seek coverage by submitting an access arrangement for approval by the regulator.
- Any person wishing to have a pipeline built can apply for approval of a competitive tender process.

Figure 3.1 **Seeking access under the Gas Access Regime**

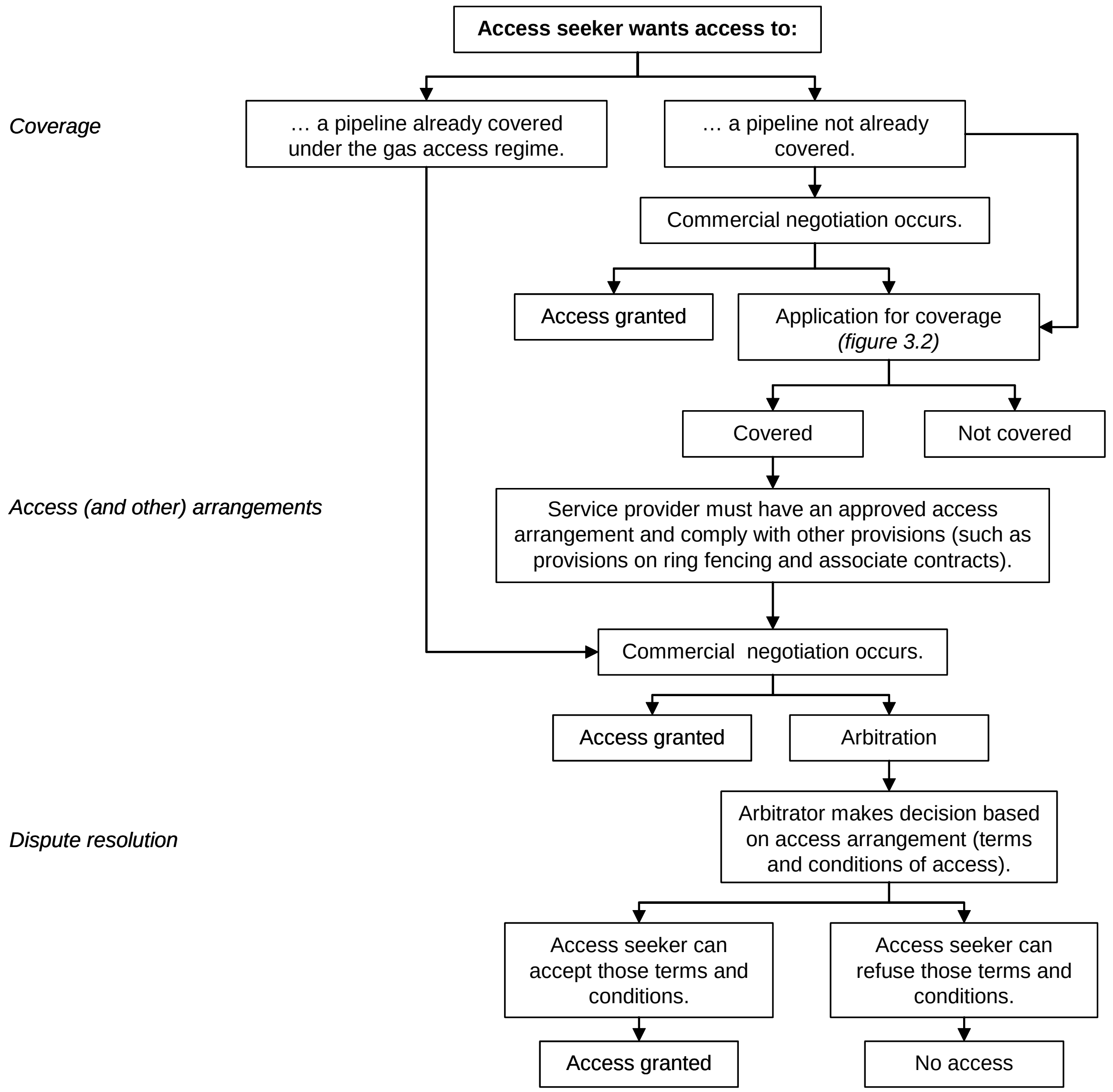
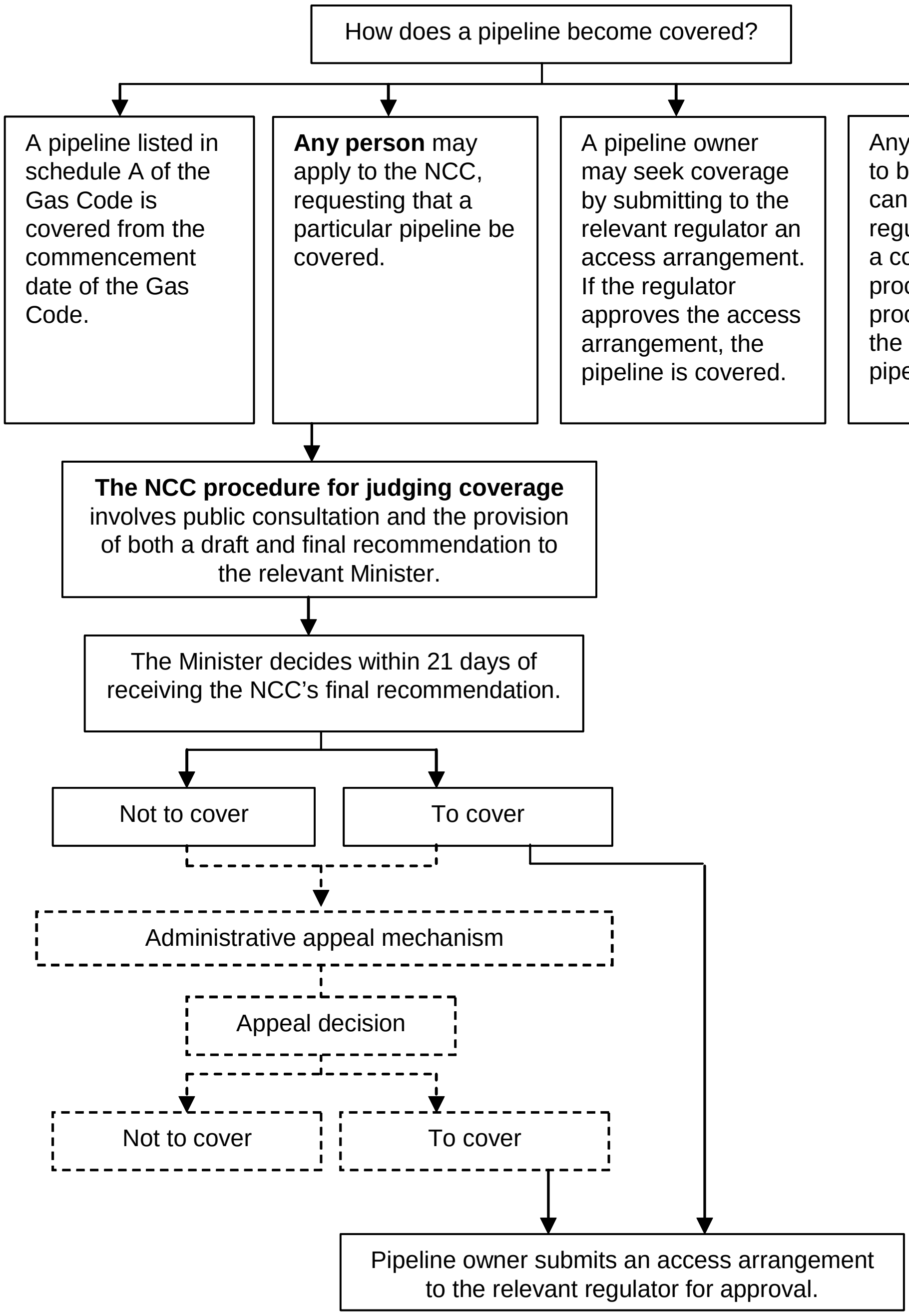


Figure 3.2 **Coverage process**



After a person has applied to the NCC for coverage, the NCC assesses the request and makes a recommendation to the relevant Minister, who then makes a decision within 21 days on whether the pipeline should be covered. The NCC must recommend that a pipeline be covered only if *all* of the following criteria are met:

- 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.

- It would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline.
- Access (or increased access) to the services provided by means of the pipeline could be provided without undue risk to human health or safety.
- Access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest.

These criteria are discussed in chapter 6.

Coverage of a pipeline can also be revoked, via a process similar to that used to apply for coverage. A merit appeal mechanism is in place for coverage and revocation of coverage decisions by the Minister. The applicant or service provider can appeal to the relevant appeal body (section 3.3). The appeal process is discussed in chapter 11.

Almost all covered pipelines were automatically covered by being listed in schedule A of the Gas Code (tables C.1 and C.2). These pipelines became covered on the day on which the access legislation in the relevant State or Territory came into operation. Twenty-two transmission pipelines/systems and 14 distribution networks were listed in schedule A. During the operation of the regime, one transmission system and three distribution networks have also been covered (as extensions to existing covered systems or through competitive tendering processes[1]). In addition, following a recommendation from the NCC, the Minister covered the Eastern Gas Pipeline, running from Longford (Victoria) to Sydney. The Australian Competition Tribunal overturned the Minister's decision on appeal.

Revocation of coverage has been sought for 15 of the transmission systems and three of the distribution networks listed in schedule A, and for the four new transmission systems and distribution networks. The Minister revoked coverage for 13 transmission systems (in whole or in part), and six distribution networks, but not for three transmission systems (in whole or in part). The Minister followed the NCC recommendation in all cases except the recent Moomba–Sydney pipeline system decision. For this system, the NCC recommended maintaining coverage but the Minister decided to revoke coverage for part of the pipeline system. A decision by the Minister is pending for the Goldfields Gas Pipeline.

The coverage and revocation decisions to date are set out in appendix C (tables C.3 and C.4).

[1] The Mildura distribution system became covered through a competitive tender process approved by the relevant regulator under transitional provisions of the Victorian Act.

Current coverage of the Gas Access Regime

Despite the revocations, many distribution networks and transmission systems are still covered by the Gas Access Regime. The Productivity Commission estimates that almost all of the throughput of distribution networks is in pipelines that are covered under the regime (table C.1). The Australian Gas Association noted that almost all customers purchase gas distribution services on terms and conditions defined by access arrangements:

> The access arrangement terms and conditions (including tariffs) set the framework for all but an extremely small number of customers … while in some networks there is an extremely limited number of customers who are served at non access arrangement terms and conditions, this is overwhelmingly due to particular customer requirements for quite specific/unusual services and arrangements. An example of this might include customers with unusual connection or metering requirements. (pers. comm., 20 November 2003)

The Australian Gas Association cautioned against interpreting figures which measure the proportion of gas sold under contracts based on access arrangement terms and conditions versus those that are not, as a sole indicator of the importance of the regime. It argued such information does not necessarily convey a sense of the importance of the regime as the effects are much more dynamic and intertemporal. Outcomes under the Gas Access Regime might be influencing investment and the scope for the use of commercial negotiations.

For transmission pipelines, it is more difficult to determine the extent of coverage under the Gas Access Regime. The Commission estimates that about 70 per cent of the kilometres of total transmission pipelines in Australia are covered pipelines (table C.2). While a large number of transmission pipelines are covered, those that are uncovered tend to be smaller pipelines with less throughput (table C.2). The proportion of total transmission pipelines that are covered is greater in terms of throughput than in terms of kilometres. However, a significant proportion of the throughput of transmission pipelines is subject to foundation and other contracts; and therefore not subject to regulatory intervention.

Access arrangements

Once a pipeline is covered, a service provider must submit an access arrangement to the relevant regulator for approval. (The relevant regulator for the type of pipeline in each jurisdiction is listed in section 3.3 of this chapter.) An access arrangement sets out the provisions under which access to a pipeline can be granted. Under the Gas Access Regime, access arrangements are approved for a period of time (tables C.5 and C.6) — after which there is a review of the access arrangement.

The service provider and access seeker are free to negotiate terms of access that differ from an existing arrangement (except in relation to queuing policy). However, an arbitrator must apply the provisions of the access arrangement in resolving any dispute.

The process to approve an access arrangement includes public consultation, leading to draft and final decisions. Between decisions, the regulator provides opportunities for the service provider to amend the proposed arrangement. If the service provider proposes amendments after the final decision, then the regulator must consider any amendments and issue a further final decision. Where the regulator is not satisfied with the final amendments, it must draft and approve the access arrangement to apply. A merit appeal mechanism is in place for service providers and users to challenge an access arrangement drafted by a regulator (chapter 11).

A regulator can approve an access arrangement only if the access arrangement satisfies the requirements specified in s.3 of the Gas Code, which include:

- a services policy
- a reference tariff and a reference tariff policy
- the terms and conditions of supply
- a capacity management policy
- a trading policy
- a queuing policy
- an extensions/expansions policy
- a revisions submission date and a revisions commencement date.

Some of the components of an access arrangement are detailed in chapter 7.

Six categories of supporting access arrangement information must be submitted at the same time as an access arrangement (attachment A of the Gas Code). This information must include:

- access and pricing principles
- capital costs
- operations and maintenance
- overheads and marketing costs
- system capacity and volume assumptions
- key performance indicators.

Thirteen transmission pipeline systems and 11 distribution networks are covered under the Gas Code and thus must have an access arrangement in place (tables C.5

and C.6). Access arrangements have been approved for all of these distribution networks and 11 of the transmission systems. Two transmission systems do not have an approved access arrangement in place. For the Kalgoorlie–Kambalda pipeline, the regulator allowed the service provider to defer submitting an access arrangement until a third party seeks access. The process for approving the access arrangement for the Goldfields Gas Pipeline is continuing.

Dispute resolution

Section 6 of the Gas Code deals with disputes between an access seeker and the service provider. If the two parties cannot agree on the terms and conditions of access, then either party may notify the regulator of a dispute. The regulator must arbitrate or appoint an arbitrator to resolve disputes over access. The dispute resolution process can include (1) an opportunity for the service provider and prospective user to make submissions to the arbitrator (2) a draft decision and (3) a final decision. No disputes have been notified yet in any of the jurisdictions covered by the Gas Code.

Ring fencing

Covered service providers are required to implement measures to ring fence their transmission or distribution business from other related activities or businesses (such as retailing). Ring fencing measures are generally concerned with separating business activities, accounting information, information flows and personnel. In a gas utility, for example, the transportation business might be required to be separated — that is, legally separated with no sharing of key staff and with secure confidentiality of information — from the other businesses of the company. The ring fencing provisions of the Gas Code are discussed in more detail in chapter 10.

3.3 Institutional framework

As part of the 1997 intergovernmental agreement, COAG agreed on an institutional framework that provides the States and Territories with flexibility in appointing a regulator, the Minister responsible for deciding coverage, and an appeal body. Consequently, different States and Territories have different institutional arrangements for transmission and distribution pipelines. Reflecting this framework, the language of the Gas Code is flexible, referring only to titles such as ‘relevant regulator’ and ‘relevant Minister’. The body responsible for each function in each jurisdiction is listed in table 3.1. (The current institutional framework is discussed in chapter 12.)

Table 3.1 **Institutional arrangements**

	Transmission	*Distribution*
Coverage decisions		
Recommendations	NCC	NCC
Decisions		
If the pipeline is located in one jurisdiction	Australian Government Minister, except in SA, WA and NT, where it is the State or Territory Minister	State or Territory Minister
If the pipeline is located in two or more jurisdictions	Australian Government Minister	State or Territory Minister of the jurisdiction 'most closely connected'
Administrative appeals		
Appeals of Australian Government Minister decisions	Australian Competition Tribunal	..
Appeals of State or Territory Minister decisions	Australian Competition Tribunal, except in SA and WA, where it is the State appeals body[a]	Australian Competition Tribunal, except in SA, Qld, Vic and WA, where it is the State appeals body[a]
Regulatory decisions, including those on access arrangements		
Decision	ACCC except in WA where it is the State regulator[b]	State or Territory regulator[b]
Administrative appeals	Australian Competition Tribunal, except in WA, where it is the State appeals body[a]	Australian Competition Tribunal, except in Qld, SA, WA and Vic, where it is the State appeals body[a]

[a] The State or Territory appeal bodies are the Queensland Gas Appeals Tribunal, the District Court (South Australia), the Essential Services Commission Appeals Panel (Victoria), and the Western Australian Gas Review Board. [b] The State or Territory regulators are the Independent Competition and Regulatory Commission (the ACT), the Independent Pricing and Regulatory Tribunal (New South Wales), the ACCC (Northern Territory), the Queensland Competition Authority, the Essential Services Commission of South Australia, the Tasmanian Energy Regulator, the Essential Services Commission (Victoria), and the Economic Regulation Authority (Western Australia, which has assumed the responsibilities of the former Office of Gas Access Regulation). **..** Not applicable.

Sources: COAG 1997; NGPAC, sub. 34, pp. 40–1.

3.4 Relationship with other legislation

National access regime

As discussed above, the Gas Access Regime is an industry-specific access regime that operates alongside the negotiate–arbitrate access regime in part IIIA of the TPA (the national access regime). It is linked to the national access regime though the process of certification.

Certification involves each State and Territory government submitting its Gas Access Regime to the NCC to establish that the regime satisfies clause 6(3) of the Competition Principles Agreement. The NCC makes a recommendation to the Australian Government Minister, who then makes the final decision on whether the regime is certified as effective.

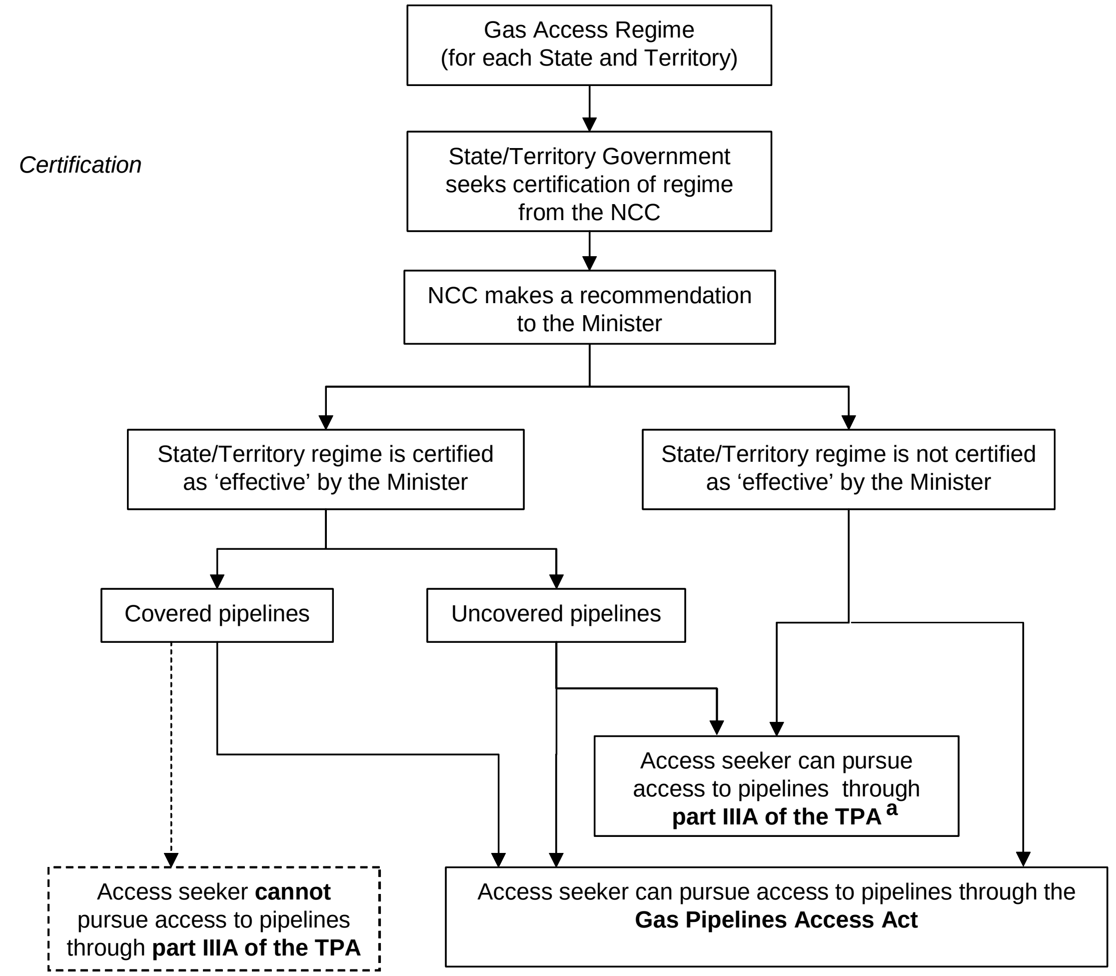
The aim of certification is to avoid regulatory duplication of, and possible forum shopping among, regimes that meet the Competition Principles Agreement criteria for an effective regime. Once an access regime is certified as effective, access seekers cannot use part IIIA of the TPA to seek access to infrastructure covered by that regime. In the case of access to pipelines, this means that pipelines covered by the Gas Access Regime, where that regime has been certified as effective, are protected from the application of the declaration provisions. On the other hand, access seekers can use part IIIA of the TPA to seek access to uncovered pipelines (figure 3.3). The NCC noted:

> The declaration provisions of part IIIA [of the TPA] potentially apply to pipelines that are not covered by the national Gas Access Regime. The fact that the national Gas Access Regime has been certified as effective in a number of jurisdictions does not mean that all pipelines within those jurisdictions are protected from the application of the declaration provisions. Whether a pipeline that is not covered under the national Gas Access Regime satisfies the declaration criteria in section 44H of the TPA would need to be determined in the context of an application for declaration under s.44G of the TPA.
>
> The current coverage criteria in the national Gas Access Regime are substantially the same as the declaration criteria in part IIIA of the TPA. This means that pipelines that do not meet the criteria for coverage under the national Gas Access Regime also would not meet the criteria for declaration under part IIIA. (sub. DR117, pp. 1–2)

As noted by the NCC, the similarities between the coverage criteria and declaration criteria remove the potential for uncovered pipelines to be declared. However, the Productivity Commission needs to be cognisant of this interaction between part IIIA and the Gas Access Regime in considering changes to the Gas Access Regime coverage criteria, and the Australian Government's proposed changes to the part IIIA declaration criteria (chapter 6).

At this stage, all States and Territories except Queensland and Tasmania have had their Gas Access Regimes certified as effective for 15 years (table 3.2).

Figure 3.3 **Seeking third party access to gas pipelines**



[a] However, a pipeline that is not covered under the Gas Access Regime is unlikely to be declared under part IIIA of the TPA because the coverage criteria for the two regimes are essentially the same.

Other State and Territory policies

In addition to interacting with part IIIA of the TPA, the Gas Access Regime interacts with other State and Territory legislation and arrangements. Examples include:

- The Essential Services Commission Gas Distribution Code and Guidelines, which require gas licensees to comply with obligations related to service standards and appropriate conduct in Victoria.
- The Essential Services Commission of South Australia licensing responsibilities for gas retailers, distributors and retail market administrators in South Australia. The Essential Services Commission of South Australia noted that it can produce codes that are binding on licensees in the gas industry (trans., p. 117).

Table 3.2 **Certification of Gas Access Regimes**

State or Territory	*Contents of State or Territory regime*	*Application date*	*Certification date*
SA	*Gas Pipelines (South Australia) Access Act 1997*	June 1998	December 1998
Qld	*Gas Pipelines Access (Queensland) Act 1998* *Gas Pipelines Access (Commonwealth) Act 1998* *Queensland Competition Authority Act 1997* *Gas Act 1965* (Queensland)	September 1998	Minister's decision pending
NSW	*Gas Pipelines Access (New South Wales) Act 1998* *Gas Pipelines Access (Commonwealth) Act 1998*	October 1998	March 2001[a]
ACT	*Gas Pipelines Access Act 1998* (ACT) *Independent Competition and Regulatory Commission Act 2000* (ACT)	January 1999	September 2000
WA	*Gas Pipelines Access (Western Australia) Act 1998*	March 1999	May 2000
Vic	*Gas Pipelines Access (Victoria) Act 1998* *Gas Pipelines Access (Commonwealth) Act 1998*	July 1999	March 2001
NT	*Gas Pipelines Access (Northern Territory) Act 1998*	January 2001	October 2001
Tas	*Gas Pipelines Access (Tasmania) Act 2000*	Yet to apply	

[a] The decision was delayed due to the pending resolution of cross-vesting issues in *Re Wakim; Ex parte McNally; Re Wakim; Ex parte Darvall; Re Brown; Ex parte Amann; Spi* [1999] HCA 27.

Source: NCC website.

- The State Agreement for the Goldfields Gas Pipeline in Western Australia, which is an alternative access regime that was enacted in 1994 to facilitate construction and regulate third party access to this pipeline.
- The *Gas Supply Act (New South Wales) 1996*, which regulates tariffs for natural gas at the retail level and might interact with obligations on distribution service providers in New South Wales.
- The *Utilities Act 2000* (ACT), which establishes a framework for regulating the provision of utilities services (including gas) in the ACT, including licensing requirements, industry codes of practice and approval of various contracts. The Act is accompanied by ring fencing guidelines with which licensees must comply.

Service providers must also comply with safety and technical requirements. As noted by M J Kimber Consultants:

> The operation and maintenance of high pressure, long distance natural gas pipelines requires compliance with a plethora of statutory requirements associated with the management of safety and risk. (sub. DR80, p. 4)

Safety and technical requirements are often regulated by a separate government body. In Victoria, the Office of Gas Safety requires pipeline licensees to satisfy health and safety, and environment standards and procedures. In Western Australia, the Department of Industry and Resources has responsibility for protecting the safety and health of employees in the mineral and petroleum resources sector, and for minimising the environmental impact of activities in this sector.

Businesses comply with many regulations, all of which have different objectives. The Gas Access Regime is not the only form of regulation that impacts on access and competition. In particular, the flexibility of the Gas Code (through provisions for discretion by the regulator) enables regulators to account for other factors (such as the legislation listed above) when making decisions under the Gas Access Regime.

Envestra noted that the interaction of these other policies and regulations with the Gas Code might be problematic:

> A trend that is becoming widespread is for State governments, in issuing licences under their State-based Acts, to establish various codes that include conditions that supplement those specified in the access arrangements approved under the Gas Access Law. For example, the Victorian Essential Services Commission (ESC) has issued a Gas Distribution Code containing obligations inter alia relating to the operation of the distribution system (for example, system maintenance, unaccounted for gas) and the provision and testing of meters. The Essential Services Commission of South Australia recently suggested that it may be appropriate to establish service standards for the distributor relating to reliability and quality of supply through a series of codes established pursuant to section 28 of the ESC Act.
>
> The main argument for including these obligations in separate codes (rather than in say access arrangements) is that they are easier to alter if modifications are required. Such codes are typically able to be amended by the regulator at any time. This not only undermines the nexus between reference tariffs and service standards or obligations, but imposes a further layer of regulation in addition to the Gas Access Law. (sub. 22, p. 12)

Envestra also noted:

> A number of governments are developing ‘other’ policies often under the guise of energy efficiency that conflict with the objectives of the Gas Access Regime. These policies actually impede investment in the natural gas industry. For example, the Victorian Government is implementing its ‘5 Star’ program. (sub. 22, p. 13)

In the case of the Goldfields Gas Pipeline, Goldfields Gas Transmission noted the need to devote a ‘good deal of resources [to] handling the [Gas] Code and the interaction with the State Agreement’ (trans., p. 58).

3.5 Nature of the Gas Access Regime

An access arrangement must include a reference tariff policy (chapter 7). Service providers and access seekers are free to negotiate access prices that differ from the reference tariff policy approved by the regulator. In this sense, some inquiry participants suggested the Gas Access Regime is like a negotiate–arbitrate model whereby parties commercially negotiate terms and conditions of access:

> The regulatory processes under the [Gas] Code provide regulators and market participants with the information needed to facilitate market processes and negotiations. Indeed, the concept of a reference tariff provides the market with a considered view as to the appropriate level of tariffs that will balance the interests of all parties. (ACCC, sub. 48, p. xiv)

> The access arrangements that have been approved are providing clear guidance on the terms and conditions that balance the interests of all parties, facilitating commercial negotiation. (ACCC, sub. 48, p. 27)

> … an approach which established upfront regulatory approval of reference tariffs for a suite of standard services, which could be accessed directly by users or used as a 'stake in the ground' around which to negotiate nonstandard services, was seen to be preferable. (NGPAC, sub. 34, p. 26)

Although the Gas Access Regime is predicated on a negotiate–arbitrate framework, there are a number of characteristics of the regime that impact on the practicality of negotiation. First, the service provider of a covered pipeline must implement an access arrangement containing reference tariffs for one or more services that a significant part of the market is likely to seek (ss2.5 and 3.3). Second, reference tariffs specified in the access arrangement must be based on estimated efficient costs of supply (ss8.2–8.4). Third, the relevant regulator must approve the access arrangement, or, where the service provider does not submit an access arrangement acceptable to the regulator, the regulator must draft and approve the access arrangement (ss2.38–2.42). Moreover, in resolving a dispute over the price of access to a reference service, the arbitrator (the regulator or an appointee) must not require the service provider or user to accept a reference service at a price other than the reference tariff. That is, the reference tariff plays a fundamental role in dispute resolution because the arbitrator is bound to apply the approved reference tariff (s.6.18).

The Gas Access Regime has thus become price regulation of the covered pipeline services available to third party access seekers. Comments by inquiry participants suggested commercial negotiation is rare and that transactions tend to take place at the regulated access price:

> Under the current Gas Access Regime commercial negotiation has been uncommon for the bulk of access seekers. Instead, access seekers have increasingly relied upon regulated default tariffs determined by regulatory authorities, and not entered into

commercial negotiations with service providers. … regulatory authorities have … become a 'proxy' tariff negotiator for large and small volume access seekers. (AGA, sub. 13, p. 32)

… it seems to Santos that the Gas Code leaves almost no room for commercial negotiation for access to covered pipelines. Once regulated there appears to be insufficient incentive for a service provider to offer any price lower than the regulated price. (Santos, sub. 29, p. 2)

In practice, access seekers will generally seek access on the terms and conditions specified in the access arrangement in the first instance, rather than attempting to pursue bilateral negotiations. (Duke Energy International, sub. 21, p. 25)

… the [Gas] Code, and the way in which it is applied by regulators, diminishes the role for commercially negotiated outcomes … (Epic Energy, sub. 37, p. 44)

It appears that, as a general rule, the access terms prescribed in existing access arrangements have become de facto access terms for all pipeline users. (WMC Resources, sub. 43, p. 29)

… the current regime … drives participants to only offer (or accept) the service associated with the reference tariff and therefore limits incentives for negotiated outcomes. (APIA, sub. 44, p. 77)

… a regulator's decision on prices predetermines the outcomes of all but the most exceptional situations, resulting in no latitude nor any margin for negotiation. (Australian Pipeline Trust, sub. 55, p. 13)

The application of the Gas Access Regime has … transformed the regime into one based on where … access seekers not seeking commercial negotiations with regulated businesses, rather opting to rely exclusively upon a narrow range of regulator imposed reference services … (Alinta/Multinet, sub. 36, p. 5)

… one of … [the Productivity Commission's] … questions in the issues paper was 'Does the access regime restrict negotiations between a service provider and a customer?'. My answer was, 'Yes, I believe it does.' … Why should the service provider negotiate with the customer? He has got no incentive to negotiate whatsoever. There is a reference tariff and there is a reference set of terms and conditions. We try to negotiate both those with the service provider and we don't have any success. (trans., p. 423)

On the other hand, a small number of participants had an opposing view:

Worsley [Alumina] believes that the [Gas] Code as it exists effectively promotes commercially negotiated outcomes. The existence of a reference service at a reference tariff acts as a 'fallback' position for both parties. The exploration of alternative outcomes is encouraged when starting from this as a secure base and there is less uncertainty with respect to price when a benchmark price is established. (Worsley Alumina, sub. 5, p. 3)

The primary intent of the [Gas] Code, through the approval of access arrangements is to facilitate commercially agreed access through the disclosure of sufficient information to assist parties in negotiations. The Code is not intended to be a substitute for commercial access. (ACCC, sub. 48, p. 34)

> WPC [Western Power Corporation] does not agree that it is a necessary outworking of a regime such as the Gas Access Regime that it will inhibit commercial negotiation. A reference tariff is a reference point against which a service provider and a prospective user can negotiate a tariff for a non-reference service. (Western Power, sub. DR115, p. 18)

Another factor might be that regulators interpret reference tariffs in a way that creates a psychological barrier in the minds of access seekers. The following statement from the ACCC, for example, could be misinterpreted as implying that anybody who negotiates a price higher than a reference tariff is paying too much:

> … in principle a negotiated tariff would only be expected to be greater than a reference tariff to the extent that the service provider can exert market power. (ACCC 2002a, p. 23)

The Productivity Commission considers that the Gas Access Regime is a form of price regulation of covered pipeline services available to third parties based on a cost-of-service model. On balance, the regime has inhibited commercial negotiation.

FINDING 3.1

The Gas Access Regime is a form of price regulation based on a cost-of-service model. It is, therefore, at the more intrusive end of regulation.

4 Is the Gas Access Regime working?

Undertaking a review of regulation essentially requires a re-examination of the benefits to be gained from having the regulation, and the costs of intervention through regulation. The Commission's approach to reviewing the benefits, costs and effectiveness of the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) is set out in section 4.1. The rationale for access regulation is discussed in the following section. Benefits of the regime are considered in section 4.3, with the costs of the regime — its impact on investment, the potential costs of regulating when there is not substantial market power, direct costs and other costs — discussed in sections 4.4–4.9. The Commission's overall assessment of the regime is set out in section 4.10.

Any assessment of the Gas Access Regime needs to look at the regulatory decision making process. The Commission notes at the outset that any implied comments about the performance of regulators does not reflect the regulator's performance as individuals but the nature of the difficult tasks given to regulators under the Gas Access Regime.

4.1 The Commission's approach

From the community's perspective, an efficient market produces the best outcome where total welfare is maximised (the 'first best' outcome). When markets do not work to allocate resources in a way that produces the best overall outcome (that is, there is market failure), there might be scope for government to intervene to improve the outcome, that is, improve efficiency.

The presence of market failure is a necessary condition, but not a sufficient condition, for government intervention to increase efficiency. Intervention should only occur if it leads to a better outcome than that which would occur in its absence, after accounting for the costs of implementing the intervention.

It is important to recognise that governments generally cannot regulate to achieve a first best outcome because, for example, their ability to intervene is limited and intervention introduces new issues and costs to the community. Regulation is thus often a second best outcome compared with competition — a notion that is well acknowledged. The Australian Competition and Consumer Commission (ACCC) noted that ‘regulation is a second best alternative that is never perfect or costless’ (sub. 48, p. xiv).

In its decision on the Eastern Gas Pipeline, the Australian Competition Tribunal stated:

> AGL [Australian Gas Light Company] argued that the extant competition was not efficient competition because the downstream and upstream markets were not fully competitive, and there was no evidence presented that the prices being charged by EGP were prices that would result from the operation of efficient competition …
>
> This argument does not take sufficient account of the fact that regulation is a second best option to competition. The complex nature of the tariff setting process, the number of assumptions it relies on, and the fact that the reference tariff is a publicly available price which may be varied by negotiation between the pipeline owner and user depending on the user’s requirements and conditions in the marketplace, all point to the fact that the reference price is not necessarily the price which would result from competition. Indeed, ACCC in its draft decision on [the Moomba–Sydney pipeline] tariffs pointed out that if the EGP did not exist the reference tariff for the [Moomba–Sydney pipeline] would be lower as it would be transporting more gas. This is not what one would expect in a competitive market (draft decision at 97). (Australian Competition Tribunal 2001, paras 109–10)

In considering whether to intervene and the appropriate form of intervention, governments need to firstly consider the benefits from intervention (that is, the size of the problem). Governments then need to consider possible forms of intervention — do they generate benefits and at what cost do they achieve those benefits? Governments should only intervene where it generates net benefits, and should implement the form of intervention that generates the greatest net benefits.

The Commission has adopted this framework in considering the effects of the regime and possible improvements. That is, the Gas Access Regime (or any regulation) should result in a net improvement in economic benefits, such that the benefits should outweigh the costs (compliance and administrative burdens, distortions and any unintended inefficiencies, for example). Similarly, recommendations for change should only be made where they improve net benefits.

There are significant challenges in assessing the effects of the Gas Access Regime. Some effects (such as the direct costs to governments of regulators administering the policy) are likely to be more readily identified than others (such as the impact of the regime on investment, particularly the disincentive to invest). Difficulties arise in establishing what would have happened without regulation (the ‘counterfactual’), such as investment levels and conditions of access (including price). Separating the effects of the Gas Access Regime from the myriad of market and other government influences (including other reforms) on the infrastructure is also difficult.

The Commission has not used models (such as general equilibrium models) to estimate the overall costs and benefits of the Gas Access Regime. Following the release of the draft report, some participants have criticised this approach.

Although models (such as general equilibrium models) can provide insights into economywide effects, using such models requires making important assumptions, including about:

- behavioural relationships (such as the responsiveness of demand to changes in price, including the ability of users to switch to substitutes)
- the counterfactual (what would have happened in the absence of the regime)
- what the specific effects of the regime have been (separate from other government reforms that occurred at the same time).

In light of the many assumptions that would need to be made, for which there is a lack of supporting evidence, the Commission has concluded that if it were to undertake modelling, the estimates of the net economic benefits derived from modelling would be imprecise and subject to questionable reliability. There would be considerable doubt about the conclusions that could reasonably be drawn regarding the magnitude of the net economic benefits of the Gas Access Regime. Instead, the Commission's approach in this inquiry is to identify the various costs and benefits, then illustrate them with qualitative and anecdotal evidence from inquiry participants. In any case, the Commission considers that undertaking modelling would bring little clarity to deciding on whether and how the existing regime might be improved, and in doing so, generate greater net benefits than the existing regime.

In considering the effects of the regime and possible improvements (discussed in later chapters), the Commission has also drawn on a checklist for assessing regulatory quality. The Office of Regulation Review developed the checklist based on a range of OECD and other reports (box 4.1).

Box 4.1 **Checklist for assessing regulatory quality**

Regulations that conform to best practice design standards are characterised by the following seven principles and features.

- Minimum necessary to achieve objectives
  - Overall benefits to the community justify costs
  - Kept simple to avoid unnecessary restrictions
  - Targeted at the problem to achieve the objectives
  - Not imposing an unnecessary burden on those affected
  - Does not restrict competition, unless demonstrated net benefit
- Not unduly prescriptive
  - Performance and outcomes focused
  - General rather than overly specific
- Accessible, transparent and accountable
  - Readily available to the public
  - Easy to understand
  - Fairly and consistently enforced
  - Flexible enough to deal with special circumstances
  - Open to appeal and review
- Integrated and consistent with other laws
  - Addresses a problem not addressed by other regulations
  - Recognises existing regulations and international obligations
- Communicated effectively
  - Written in 'plain language'
  - Clear and concise
- Mindful of the compliance burden imposed
  - Proportionate to the problem
  - Set at a level that avoids unnecessary costs
- Enforceable
  - Provides the minimum incentives needed for reasonable compliance
  - Able to be monitored and policed effectively

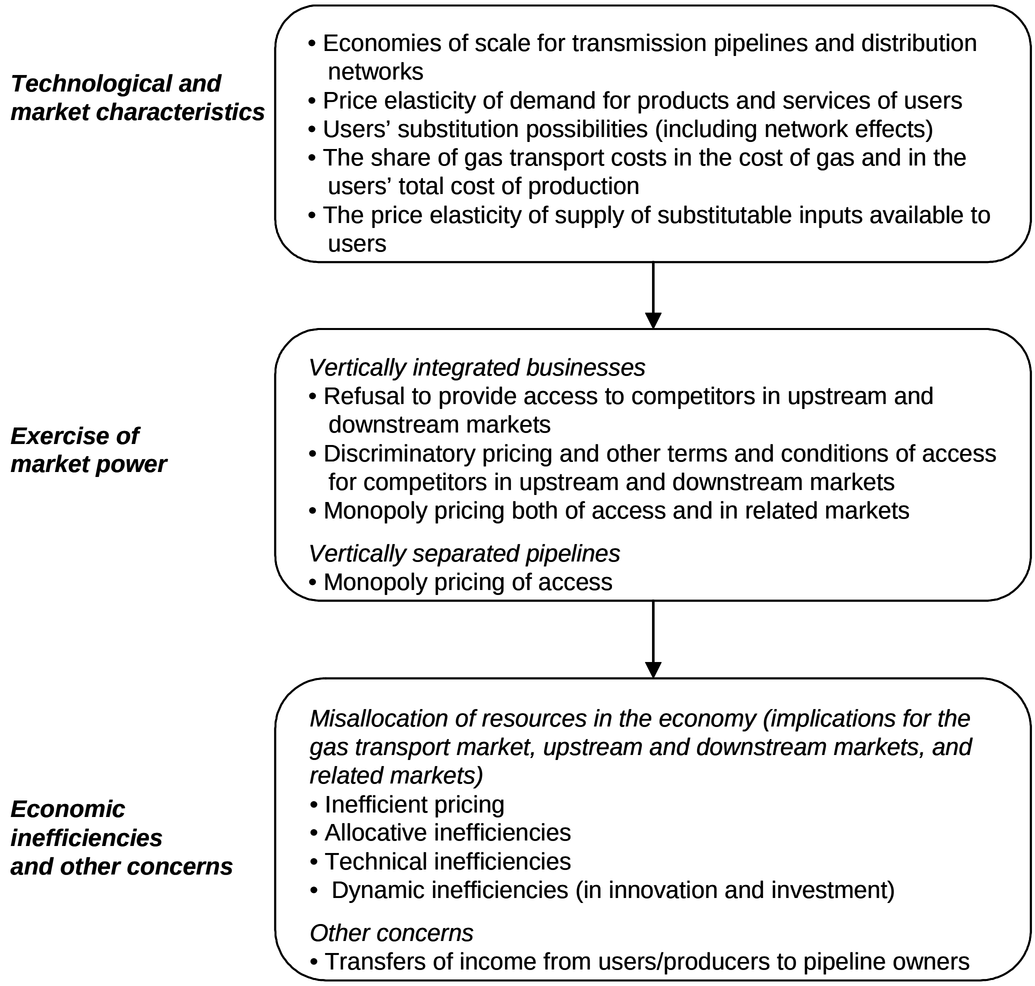
Source: PC 2003, p. 53.

4.2 Rationale for regulation

What is the problem in natural gas markets?

Any policy intervention should target a clearly identified set of problems. As discussed in chapter 2, individual transmission pipelines and distribution networks exhibit natural monopoly characteristics. Such characteristics, combined with weak competitive forces, might enable transmission and distribution businesses to exercise market power and inhibit competition in upstream and downstream markets (figure 4.1).

Figure 4.1 **The rationale for regulating access to natural gas pipelines**



Pipelines might exert market power in two ways. First, a vertically integrated business might seek to limit competition in upstream and downstream markets by denying competitors access to the pipeline. Second, the owner or operator (service provider) of a pipeline might seek to use market power to charge monopoly prices.

This concern underpins access regulation as much as does the denial of access (PC 2001c, p. 39).

In relation to vertical integration, the Hilmer Committee noted:

> Where the owner of the 'essential facility' is vertically integrated with potentially competitive activities in upstream or downstream markets — as is commonly the case with traditional public monopolies such as telecommunications, electricity and rail — the potential to charge monopoly prices may be combined with an incentive to inhibit competitors' access to the facility. For example, a business that owned an electricity transmission grid and was also participating in the electricity generation market could restrict access to the grid to prevent or limit competition in the generation market. Even the prospect of such behaviour may be sufficient to deter entry to, or limit rigorous competition in, markets that are dependent on access to an essential facility. (Hilmer Committee 1993, p. 241)

Implications of exercising market power

Exercising market power and other anticompetitive behaviours can lead to economic inefficiencies, including allocative inefficiency.

The allocative efficiency costs of exercising market power by charging monopoly prices can be illustrated using a simplified framework (box 4.2). Other effects also arise from service providers exercising market power. Service providers exercising market power might reduce the quality or reliability of their service for a given price due to the lack of competitors.

Businesses with enduring market power might also have less incentive to seek out new ways to improve product and service quality and be innovative in general, preferring instead a 'quiet life' by paying less attention to the demands of consumers (PC 2002b, p. 84). These losses are additional to the standard allocative efficiency losses illustrated in box 4.2. Using the illustrative example in box 4.2, dynamic efficiency improvements might shift the average cost and marginal cost curves down, resulting in greater net economic benefits over time. The broad package of reforms to the gas industry (including the Gas Access Regime) is likely to have resulted in significant dynamic efficiency gains to the economy, although the future dynamic efficiency gains are likely to be smaller. Regulatory regimes might encourage dynamic efficiency improvements, depending upon their design. The Pacific Economics Group noted:

> Many utility industries have historically been subject to lower-powered regulatory schemes, like rate of return regulation. Economists generally believe that rate of return regulation does not create optimal incentives to contain unit cost. Industry [total factor productivity] and input price trends calculated from historical data will naturally reflect the industry's historical unit cost performance under these low-powered regulatory mechanisms.

> Rate indexing is designed to create stronger performance incentives than traditional regulation. Superior incentives should lead, in turn, to more rapid [total factor productivity] growth relative to historical norms. (sub. DR113, p. 5)

The efficiency costs of inefficient pricing in gas transportation go beyond the immediate effects in the market for gas transportation services. There are flow-on efficiency effects in the broader economy. The denial of access or exercise of market power particularly affects upstream and downstream users.

An important issue is that the marginal efficiency gains from intervention decline as the exercising of market power is reduced, because the gap between 'efficient price' and monopoly price narrows (as illustrated in box 4.2). This stylised representation has been used by the Commission in a number of reports, for example, its reviews of the national access regime and regulation of airport services (PC 2001c and 2002b, respectively).

Box 4.2 **Interaction between efficiency losses from and level of market power: a stylised, comparative static, 'textbook' model**

A service provider with market power seeks to maximise profits. In the standard textbook model, it does this by raising the price. The resulting reduction in production and consumption, to less than the optimal level, is an efficiency loss — often referred to as monopoly deadweight loss. Note that the simplified, static representation presented here does not reflect the many complicated factors in a dynamic world, including market conditions (raised in chapter 2) and uncertainty (later in this chapter and in chapter 7). As indicated in this simple figure, the monopolist chooses a price and quantity corresponding to point a, whereas the lowest price the facility owner could sustain in the longer term would be at point b (where price equals average cost).

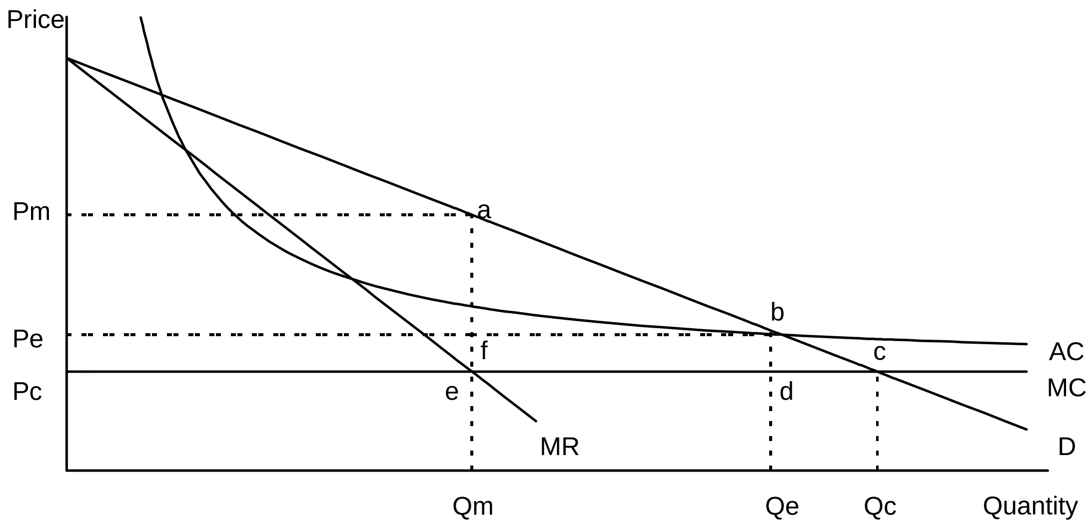
Moving from point a to point b both improves overall efficiency and involves a transfer of income from the monopolist to users. First, the net efficiency gain is the area abde, derived from a gross improvement of area abQ_eQ_m, less the resource cost of the improvement being the area edQ_eQ_m. This net efficiency gain is distributed to consumers (triangle abf) and service providers (rectangle fbde). Second, there is a transfer of income from service providers to users of the area afP_eP_m.

The size of the improvement in efficiency depends on the business' cost structure and the price elasticity of demand. For a given marginal cost, and assuming no price discrimination, the lower the price responsiveness (elasticity) of demand, the greater the optimal price mark-up over cost.

A business might reduce efficiency losses through some price discrimination. If the business was able to price discriminate fully, the adverse efficiency gains would completely disappear (the business would earn excess profits at the expense of consumers, but with no loss in economic efficiency).

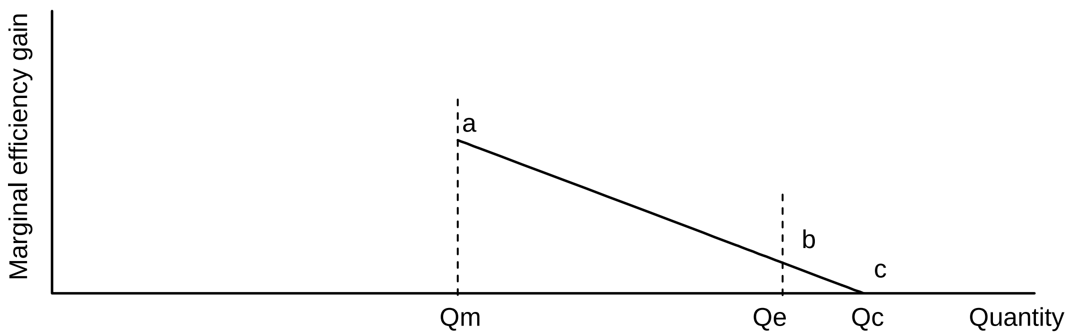
(Continued next page)

Box 4.2 (continued)



Marginal efficiency gains decline as the gap between price and marginal cost narrows

The marginal efficiency gain from the increase in consumption arising from lowering the price, decreases as the quantity is increased from Q_m to Q_e.



Sources: PC 2002b, 2001c; Carlton and Perloff 1994.

Finally, as discussed in box 4.2, higher prices (or the benefits to the service provider associated with denial of access) mean a transfer of income from users to service providers. This is not an efficiency loss to the community (provided the transfer occurs between Australian residents). Nonetheless, any impact on the distribution of income might be a concern. The Commission considers, however, that using access regulation to redistribute income would be inefficient (PC 2001c, 2001e and 2002b). Other policies generally target income distribution more effectively and efficiently.

Is there a case for a gas industry-specific regime?

There is a rationale for regulating access to gas pipelines with market power (noted above and chapter 2). An important question is whether there is a case for having a gas industry-specific access regime or whether relying on the general national access regime (part IIIA of the *Trade Practices Act 1974* [TPA]) (chapter 3) would be more appropriate.

In its review of the national access regime, the Commission compared the advantages and disadvantages of a generic regime with those of an industry-specific regime (PC 2001c, pp. 116–17). It determined that a generic approach regime might:

- result in a consistent approach across sectors
- accommodate surprise candidates for access regulation
- disseminate regulatory lessons across sectors without dispersing regulatory expertise
- reduce the prospect of regulatory capture by industry.

On the other hand, an industry-specific regime has characteristics that might make it preferable for a particular industry. It might:

- provide scope for the access arrangements to explicitly recognise differences across infrastructure sectors
- provide greater certainty to access providers and seekers
- reduce transaction costs in an industry that is likely to have multiple third party access seekers.

In implementing the Gas Access Regime, governments considered that a national gas industry-specific regime would enhance certainty, uniformity and consistency. Given the potential for a number of pipelines to require regulation, relying on the general national access regime might mean different regulatory arrangements (based on negotiation and arbitration) proliferate, which could hinder the development of a national market for gas. Further, governments considered there were likely to be multiple access seekers for particular pipelines each involving transaction costs. For this reason, the more prescribed access arrangements in the Gas Access Regime compared with part IIIA, are less costly overall.

State and Territory governments also perceived the need for specific regulation of access for gas pipelines, with a 'proliferation of individual regimes involving regulatory arrangements and institutions of varying quality … already occurring' (House of Representatives 1998, para. 33).

The Council of Australian Governments (COAG) Energy Market Review noted:

> Clearly there are conflicting views regarding the impacts the Gas Code is having. While strong statements have been made by a range of participants regarding the necessity of the Gas Code, the panel considers that economic regulation will continue to be required for some key infrastructure in the Australian gas market. However, the form of that regulation should remain consistent with the needs of the market as it develops. (EMR 2002, p. 192)

Inquiry participants also recognised the need for a gas industry-specific regime. Newmont Australia considered that 'the Gas Code should be retained but be modified to ensure efficient access to third parties on reasonable terms' (sub. 50, p. 3). Western Power supported retaining a gas industry-specific access regime (sub. DR115, p. 19).

The Australian Petroleum Production and Exploration Association noted:

> All of the upstream industry agree that there's a need for an effective and efficient access regime where there is a capacity for monopoly power to exist, and the stress is on the words 'effective and efficient', 'where there is monopoly power'. Therefore we argue we want to retain the regime. We don't want to abolish it. (trans., p. 353)

The ACCC considered that there is a case for retaining both an industry-specific regime and a general access regime, and noted:

> The [Gas] Code has been developed to be consistent with part IIIA [of the TPA] while addressing the specific needs of the gas industry. It establishes a process that is more accessible for multiple access seekers than would operate under the generic provisions of part IIIA. It also requires access arrangements to meet criteria that are more specific to the needs of the industry than the criteria that would apply either to an undertaking or an arbitration determination under the generic provisions of part IIIA. (sub. 48, p. 31)

The Productivity Commission considers that the original arguments for a gas industry-specific access regime are still valid. A number of pipelines might still warrant regulation. A national gas access framework that accounts for specific characteristics of the gas market is likely to involve lower transaction costs and larger benefits. Further, there is likely to be more than one access seeker for some pipelines (particularly for gas distribution networks). A generally available access arrangement for such pipelines is likely to involve lower costs than those of requiring each access seeker to seek access through the negotiate–arbitrate framework of the national access regime (part IIIA of the TPA). The absence of a national Gas Access Regime might also result in the reintroduction of individual State and Territory regimes. Consequently, the Commission considers that an industry-specific national access regime for gas transmission pipelines and distribution networks is still warranted.

Nonetheless, it is important for regulatory decisions to be cognisant that the gas market is changing and to support emerging competition. Minister Macfarlane echoed such sentiments in the recent Moomba–Sydney pipeline revocation decision:

> The decision to revoke the Moomba to Marsden section is based on the developing network in south-east Australia which limits the proponent's ability to exercise market power … We are moving away from an assumption of regulation in this sector, but this case warrants some degree of regulation. I'm focused on creating a competitive energy market and some level of regulation is needed while we are still in a transitional phase. (Macfarlane 2003b, p. 1)

FINDING 4.1

An industry-specific access regime is appropriate for gas transmission pipelines and distribution networks because of its advantages over the negotiate–arbitrate model of the national access regime.

4.3 Benefits of the regime

The potential benefits of the Gas Access Regime are directly linked to its rationale (section 4.2). That is, the benefits arise from curbing the monopoly power of service providers (where it exists) to facilitate competition in upstream and downstream markets and to reduce inefficiency from monopoly pricing in the gas transportation market. Inquiry participants tended to provide comments and evidence mostly on the costs of regulation, possibly because costs are more readily identifiable than benefits. Also, some inquiry participants considered that the benefits are only beginning to emerge. The ACCC noted that 'Australia is only just starting to reap the benefits of the emergence of competition in dependent markets' (sub. 48, p. 11).

It is important to note that the Gas Access Regime was implemented as part of a package of broader reforms of the gas industry (chapter 3). The Australian Petroleum Production and Exploration Association noted:

> … the reforms of the 1990s which included regulated access to downstream transmission and distribution services have led to significant benefits to the gas market and end consumers. Such benefits include more dynamic and competitive upstream and downstream sectors, diversification of supply sources and ultimately customer choice. These benefits have come from (1) government policies of customer contestability, (2) regulated access to the existing monopoly transmission and distribution infrastructure, (3) new supply opportunities opening in the market, and (4) the development of new transmission pipelines. (sub. 6, pp. 1–2)

The Australian Gas Association (AGA) noted:

> There is a presumption amongst regulatory authorities that they are responsible for driving efficiencies in regulated businesses or improving service standards. However,

regardless of the regime, private regulated businesses must still satisfy their shareholders and investors. This means making prudent business decisions, increasing efficiencies wherever possible and, notably in the case of gas, improving customer service to maximise customer retention and energy market share.

[The removal of legislative barriers to interstate trade in gas, a commitment to competitive reforms of the upstream gas sector, and full retail competition in gas], together with the commercial imperatives flowing from predominantly private ownership of the gas industry since the 1990s, have led to efficient improvements and, in some cases, reductions in prices. While the development of an access regime played a role in promoting competition and efficiency benefits, it is not appropriate to attribute any identified increases in the efficiency of the gas industry as a whole to only one element of the reforms described. (sub. 13, p. 17)

Distinguishing the benefits of the Gas Access Regime from those of gas sector reform more generally is difficult.

Promoting competition in upstream and downstream markets

In relation to upstream competition, the Queensland Government noted:

There has recently been positive evidence of the development of upstream competition in Queensland, where the rapidly developing coal seam gas industry is providing field on field competition. The development of this industry has directly benefited from the capacity of pipelines such as the Wallumbilla–Gladstone pipeline … (sub. 63, p. 9)

BHP Billiton noted that activity and diversity has increased substantially in the upstream gas sector since the inception of the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas 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. (sub. 26, p. 23)

The Energy Users Coalition of Victoria and the Electricity Consumers Coalition of South Australia considered that the Gas Code has resulted in 'an increase in the exploration and development of new gas supplies' (sub. 49, p. 7).

WMC Resources considered that there have been significant benefits upstream:

WMC Resources submits that there is evidence that the Gas Access Regime has had major beneficial ramifications for both investment and competition in upstream (gas

> supply) markets. However, access to gas transportation infrastructure is a necessary, but not a sufficient, condition for promoting investment and competition in upstream markets.
>
> The impact of the Gas Access Regime appears to have been different in different locations, which is likely to be a function of the differing characteristics of the relevant upstream and downstream markets.
>
> … WMC Resources sees that, particularly in Western Australia, upstream competition is developing [due to] the restructuring of the long-term gas supply contracts which were in place between the State Energy Commission of Western Australia and the North West Shelf Gas Joint Venture and the development of open access (albeit sometimes limited) on the [Dampier–Bunbury pipeline] and the Goldfields Gas Pipeline. (sub. 43, pp. 34–5)

Envestra noted that access has allowed retailers to enter new markets, but acknowledged that a national market for gas is still being developed:

> Open access to distribution systems has provided retailers with the means of entry to various markets. However, a national market for natural gas can only develop when participants are able to have gas transported with minimal constraints through various transmission pipelines and hubs, without the need to create bypass connections and inefficient duplications of infrastructure. On this basis, the [Gas Access] Regime has not facilitated the development of a national market. Despite the regime, however, a national market for gas is slowly developing. (sub. 22, p. 28)

Similarly, the ACCC noted:

> There are long lead times for development of new gas fields and pipelines. Nevertheless, new pipelines are now bringing new gas supplies to markets. We are starting to see the potential for a more competitive gas supply industry — but there is still some way to go. (sub. 48, pp. 11–12)

The Energy Users Association of Australia noted:

> The advent of third party access has also promoted interbasin gas-on-gas competition, and there is potential for gas retail competition to also develop in future. Also more consumers, including those in regional centres, now have access to gas supply. The development of a national gas grid in south-eastern Australia has also commenced and these are dynamic results in a hitherto underdeveloped and pretty immature gas market and they stem, at least partly, in our view, from the existence and implementation of a Gas Access Regime. (trans., pp. 260–1)

Origin Energy also noted the benefits from information flows:

> Regarding positive outcomes, the regime has provided for the development of access arrangements for covered pipelines generally understood by all interested participants. To the extent that a pipeline qualifies as a covered asset, the [Gas] Code has provided for an improvement in information flows to users and producers, such that the basis of haulage tariffs is understood. This has assisted users in assessing whether a contractual

> arrangement for haulage services compares positively to an alternative (which may also include a separate supply source). (sub. 52, p. 2)

As well as bringing about access to covered pipelines, the threat of regulation might contribute to increased third party access and transparency. Duke Energy International has a nondiscriminatory access policy for the Eastern Gas and Tasmanian pipelines. It might have been motivated partly by a desire to demonstrate that it is not exercising market power, and therefore, to avoid regulation:

> It is my firm belief that if a company is operating competitive, nondiscriminatory, open access infrastructure without being covered by the [Gas] Code, then regulation should not apply. Why impose the burden of costly and prescriptive regulation when the desired effect can be achieved through a behavioural system such as the nondiscriminatory access approach. (Duke Energy International, sub. 61, attachment prepared by Julie Dill, p. 4)

The benefits of the Gas Access Regime might also extend to quality and innovation in service. Envestra noted that distribution network access has encouraged retailers to compete and to develop value-adding services for customers (sub. 22, p. 8). In contrast, the Australian Pipeline Industry Association (APIA) considered that the application of the Gas Code jeopardises continued investment in innovation, because the regulatory parameters provide no incentive to continue research (sub. 44, p. 39).

Reducing inefficiency from monopoly pricing in the gas transportation market

The Gas Access Regime explicitly requires service providers to disclose a reference tariff (discussed in chapter 7) approved by the regulator for each of their reference services. Regulators aim to determine ‘efficient’ prices, which is a problematic approach that is unlikely to achieve the outcome of a competitive market. In this sense, price regulation is a second best outcome.

If a pipeline is covered by the Gas Access Regime because it has the potential to exercise market power, then the price for third party access could be expected to be lower after coverage. Lower prices are beneficial for downstream product markets in which gas is an input to production. Mining industries, for example, use gas for electricity generation and thus might benefit from a cheaper input. Lower prices might benefit upstream users too if cheaper prices boost demand for their products.

The potential benefits of regulating pipelines with foundation customers, where these customers had countervailing power in negotiating their contracts (such as when pipeline development is contestable), are likely to be lower than the benefits for other pipelines. The market power of service providers with foundation customers is likely to be constrained (chapter 2), so the potential benefits of regulating pipeline access might relate only to future customers using any spare capacity in that pipeline.

Inquiry participants broadly considered that the Gas Access Regime has lowered the prices for gas transportation, as argued by the Energy Users Coalition of Victoria and the Electricity Consumers Coalition of South Australia (sub. 49, p. 7) and the Energy Markets Reform Forum (sub. 30, p. 12). The Energy Users Association of Australia noted:

> The implementation of the Gas Access Regime, since the mid 1990s, has brought benefits to major gas users. Transmission and distribution network prices have been reduced, reflecting regulatory determinations, and that has reduced monopoly rents. (trans., p. 260)

The Hunter Gas Users Group stated:

> In general, … the national Gas Access Regime has worked in providing conditions for more effective and competitive gas transportation tariffs, but much more needs to be achieved to provide gas users with the competitive pricing promised under the regime. (sub. 4, p. 3)

The Australian Gas Light Company (AGL) noted that removing cross-subsidies and other costs has resulted in significant price reductions across its distribution networks in New South Wales:

> … cross-subsidies and other costs have been removed and passed on to consumers in significantly lower prices so that, in the case of AGL's gas distribution networks in New South Wales, average contract market prices are now about 35 per cent of their 1996-97 levels in real terms. (sub. 32, p. 4)

BHP Petroleum's submission to the Commission's review of part IIIA of the TPA noted:

> The benefits delivered to consumers from open access are significant. In 1996 before the commencement of open access, large consumers (those consuming more than 10 TJ pa) in NSW paid $146 million for distribution and retail services. [The Independent Pricing and Access Regulation Tribunal, IPART] determined that $3.8 million of the $146 million was the retail component. In 2000 IPART determined that larger consumers in NSW should pay a total of $46 million for distribution services on AGLGN's NSW system, a reduction of $96 million pa. In addition, small consumers continue to benefit from real declining prices for distribution services. (BHP Petroleum 2001, cited in Energy Markets Reform Forum, sub. 30, p. 15)

The ACCC noted the problems in quantifying the benefits from lower prices:

> While it is difficult to establish the quantum of monopoly pricing that would arise in the absence of access regulation, some insights might be drawn from the material

> presented [elsewhere in the ACCC's submission] shows the initial prices sought by service providers compared to the final prices permitted by the ACCC for each regulated transmission pipeline. These results need to be interpreted with caution as it is impossible to determine the counterfactual, however, they do suggest that pipeline operators desire the option to raise prices significantly above those permitted under the regulatory regime. (sub. 48, p. 67)

However, just as the prices sought by service providers might not reflect the prices that they would charge without regulation, the prices approved by the ACCC might not reflect 'efficient prices', given the potential for regulatory error (chapter 7). Such regulatory error not only has effects on prices, but it can have wider implications on market outcomes and investment.

Following the release of the draft report for this inquiry, the ACCC released a study prepared by ACIL Tasman that estimated the impact of access regulation under the Gas Code, the National Electricity Code and part IIIA of the TPA (sub. DR101, appendix H). The ACCC concluded that over the period 1998-99 to 2012-13, access regulation in the gas and electricity sectors:

> … is likely to increase Australia's GDP (on a cumulative basis) by between $2.2 billion and $11.0 billion. ACIL Tasman estimates that approximately 10 per cent of these benefits can be attributed to the gas access regime.
>
> This substantial benefit arises due to lower prices which stimulate greater usage of electricity and gas and greater activity in upstream and downstream industries. Approximately 80 per cent of the net economic benefits over the full 15 year period arise in the next 10 years. (sub. DR101, pp. 29–30)

However, the Productivity Commission considers these estimates are subject to significant uncertainty, arising from uncertainties about the counterfactual scenario, aggregation error, the price elasticity of demand for gas and the strategic behaviour of agents along the supply chain. As well, the analysis does not capture all of the benefits from greater competition in related markets and does not fully account for all of the regulatory costs, which might be significant. These issues are discussed further in appendix D. In the Commission's view, although the results suggest there is a net economic benefit, the magnitude of the net benefit of the Gas Access Regime is uncertain.

Envestra noted that large users too have benefited from lower gas costs as a result of removing cross-subsidies to smaller users (sub. 22, p. 8). There are limits on the extent to which lower gas transport prices should be perceived as a benefit of access regulation. First, if upstream producers have market power, they might capture rents removed from pipelines, so there is no overall benefit to downstream users in the form of lower prices.

KPMG noted:

> … taking all or a large part of the ‘rent’ out of the pipeline segment of the industry chain may simply result in a redistribution of rent to the other parts of the chain (likely to be the gas producers). (sub. 20, p. 17)

Second, access regulation might result in transfers being redistributed from service providers to users. Such transfers are not efficiency gains. The private benefits in terms of the net transfer of income to gas producers and/or users are not part of the overall benefits of regulation. Rather, the benefits of access regulation to society will depend on the extent to which the regulation reduces inefficiencies that otherwise would arise from the exercising of market power. These benefits are diffuse and difficult to measure (AGA, sub. 13, p. 19).

Third, a reduction in access prices is not conclusive evidence of an effectively operating regime. The AGA cautioned against interpreting short-term price falls as benefits of the regime because they might be ‘evidence of systemic underinvestment’ (sub. 13, p. 19). Envestra also noted:

> A key task of regulators is to set regulated revenues such that they balance the interests of investors and consumers. However, the reductions in revenue imposed on businesses have been savage. Envestra’s revenue has been reduced by up to 22 per cent compared to that initially sought. (sub. 22, p. 10)

Competition is a dynamic concept, and prices might vary over time in competitive markets as businesses innovate and compete. Professor Stephen Littlechild noted:

> JM Clark [the originator of the concept of workable competition in 1940] himself was particularly concerned about the static nature of perfect competition. ‘As a standard of so-called “perfection”, it is one legged, focusing on the essentially static objective of cost–price equilibrium, to the neglect of the dynamic objectives of progress’. (Allgas Energy, sub. 25, attachment 2, p. 77)

The evidence presented to the Commission broadly supports the rationale for regulating access to gas pipelines. The Commission considers that the Gas Access Regime has opened the way for third party access to pipelines, lowered gas transportation prices and facilitated competition in upstream and downstream markets.

FINDING 4.2

The Gas Access Regime has delivered benefits through determining the terms of third party access to pipelines and facilitating competition in upstream and downstream markets.

4.4 Impact on pipeline investment — conceptual issues

This section outlines a conceptual framework for assessing how regulation affects pipeline investment.

At a simplified level, the decision to invest depends on an investment's riskiness and expected return. Investors are generally thought to be risk averse, meaning that they will require a higher expected return to compensate for greater risk (Brealey and Myers 1996). That is, there is a risk–return tradeoff.

Box 4.3 outlines various possible sources of risk for gas pipeline investors, and how risk might have increased over time due to restructuring of the energy industry.

The risk associated with an investment is rarely, if ever, known with certainty. As a result, investment decisions have to be made under uncertainty. This forces investors to make subjective judgments about risk.

An investor's subjective judgment of risk should include an assessment of how risk would change if investment was delayed (Dixit and Pindyck 1994). This is because delaying an irreversible investment until more is known about future market conditions can reduce risk and so make a project more attractive. That is, it is worthwhile for investors to consider the timing of an investment, and this requires a subjective assessment of how risk will change over time.

For pipeline investors, the timing decision is more complex than a simple choice between either investing or not investing in a specific plant at a particular point in time. Rather, capacity can be built incrementally to ensure that, based on a subjective judgment by the investor, risk will never become so high that the expected return provides inadequate compensation. APIA summarised this process as follows:

> In any proposed project, the developer must weigh up the [uncertain] probability and timing of future demand growth and whether it is best to build a smaller diameter pipeline with the thought of increasing capacity in the future via an option such as adding additional compression or simply building a larger diameter pipeline in the first instance which will be capable of satisfying future forecast demand. (sub. 44, p. 16)

Ideally, investment would be efficient in the sense that its level, timing and other properties generate the greatest possible net benefit for society as a whole. This is a theoretical ideal that is unlikely to be achieved *ex post*. It is difficult enough to make investment efficient in an expected sense, based on a subjective judgment about risk. Actual outcomes often differ from those that were forecast and so investment will rarely correspond to an optimal situation *ex post*.

Box 4.3 Risks faced by pipeline investors

Pipeline investment risks might include:

- possible variations in costs during the construction phase (for example, the costs of procuring materials)
- uncertainty about future market outcomes (for example, the possibility that demand for a facility will abate due to the emergence of competition or changes in users' circumstances, and that gas supply will decline before the physical life of the pipeline has ended)
- operational risks (for example, changes to environmental, safety and technical requirements)
- uncertainty about future technology developments.

Given the scale of investment in essential infrastructure, and the fact that, once in place, the assets are 'sunk' with few alternative uses, the risks associated with pipeline investment are especially high. Changes in Australia's energy industry over the past decade might have even increased the pipeline investment risk via:

- the structural separation, corporatisation and privatisation of government-owned enterprises
- the introduction of third party access regulation.

The gas sector used to be somewhat insulated from market risks. Large State-owned monopolies had a well defined market and protection from competitive entry and price competition. Public utilities had some ability to tax users by using legislated monopoly policy, or receive transfers from taxpayers, thereby transferring risks to users and taxpayers.

Changes to the structure of the gas industry, particularly vertical separation, might have made investments more risky. Increased competition from other pipelines, retailers and gas basins is no longer internalised within the public monopoly. Thus, information flows and assured upstream suppliers or downstream sales might no longer exist for a vertically separate business. The bargaining power of individual businesses in various parts of the gas supply chain are changing over time, and bargaining outcomes are more uncertain.

Helfat and Teece (1987) explored the relationship between vertical integration and uncertainty in the United States. They presented evidence that vertically separate businesses have higher systematic or undiversifiable risk. When a business is vertically separate, decision making is more complex because planning the allocation of resources is more uncertain (Helfat and Teece 1987, p. 320).

An issue of concern for this inquiry is that weak competitive pressures could lead to investment that is less efficient than it would otherwise be. At the extreme, a monopolist that does not face the potential threat of competition could maximise profit by limiting supply so as to raise its price well above cost. This is undesirable from society’s perspective if there are potential customers that are willing to pay at least the additional cost of production but not as much as the monopoly price.

In theory, regulation can be used to constrain monopoly pricing. However, regulation has limitations and there is an extensive literature demonstrating the potential for regulation to make investment less efficient than intended (see, for example, Kolbe, Tye and Myers 1993; Train 1991). But, as the ACCC noted:

> Whether regulation distorts investment depends upon the particular characteristics of the regulatory regime and the incentives faced by regulators. (sub. DR101, p. 65)

The greatest concern for this inquiry is that the Gas Access Regime’s form of cost-based price regulation leads to inefficient investment because of:

- *regulatory error* — mistakes are made in applying regulation
- *regulatory risk* — uncertainty about how regulation is applied increases the riskiness of investment
- *asymmetric truncation* — profit is curtailed if it is better than expected.

Regulatory error can lead to regulated prices that are either much lower or higher than efficient costs. Regulatory risk introduces an additional source of variability to profit that will make investment less attractive, since investors are risk averse. Asymmetric truncation can reduce expected economic profit below zero (box 4.4). Economic profit is the difference between revenue and the opportunity cost of all inputs including capital. This differs from accounting profit, which focuses on monetary outlays.

Regulatory error

In the review of the national access regime, the Commission (PC 2001c, pp. 82–3) considered the tradeoff between regulatory errors that overcompensate service providers and those that undercompensate. Regulatory error that undercompensates service providers could discourage investments of considerable benefit, with flow-on effects for investment in related markets. On the other hand, regulatory error that overcompensates service providers distorts decision making. The Commission considered that both types of regulatory error are likely to distort investment and have adverse efficiency implications.

Box 4.4 Asymmetric truncation and investment

Investments are risky and so have a distribution of possible profits. The mean of an investment's profit distribution is often used to measure the investment's expected profit.

In essence, expected economic profit is constrained to zero (in net present value terms) under the Gas Access Regime to encourage competitive behaviour *ex ante* (economic profit is the difference between revenue and the opportunity cost of inputs). However, the presence of risk means that *actual* economic profit might not be zero. That is, a high actual profit can be consistent with competitive behaviour. Nevertheless, regulators might tend to interpret a high actual profit as evidence of monopolistic behaviour because of the following:

- *asymmetry of observing regulatory errors* — failure to constrain monopoly profits is easier to observe than mistakenly regulating competitive behaviour
- *regulator risk aversion* — when in doubt about the existence of monopolistic behaviour, the regulator tends to err on the side of caution by regulating behaviour
- *regulatory capture* — the regulator's consumer advocacy role biases regulatory decisions in favour of consumers at the expense of economywide benefits
- *mistrust of regulated businesses* — the regulator perceives that businesses try to mislead it by withholding or distorting information.

Hence, regulators might be tempted to curtail high profits. This is termed asymmetric truncation because only high profits are curtailed.

If a profit distribution is asymmetrically truncated, then its mean (expected profit) will fall. As noted by Train (1991):

> If the firm makes less than the allowed rate of return in 'bad' years and yet is not allowed to make more than the [upper bound of] return[s] in 'good' years, the firm's average return over time is less than the allowed return. (Train 1991, p. 105)

In some cases, an investor's expected economic profit will fall below zero. This will occur if the investor perceives that:

- regulation constrains expected economic profit *without* asymmetric truncation to zero in order to mimic a competitive market
- regulators asymmetrically truncate actual profits of businesses that behave competitively.

A regulator is unlikely to adjust regulated prices upwards to take account of this problem, since it would be an admission that it mistakenly truncates the profits of businesses that behave competitively.

Some inquiry participants suggested it is better to err on the side of overcompensating investors, because the cost of less investment is greater than the cost associated with monopoly rents:

> … the costs and efficiency impacts of underinvestment in infrastructure assets, flowing from access prices that are set too low, will outweigh any smaller efficiency impacts of access prices being set marginally too high. (AGA, sub. 68, p. 2)

> … we stress that the costs of failing to remove the last cent of monopoly profit from network tariffs is small relative to the costs of reduced investment. For this reason the [Gas] Code should be amended to be biased towards investment. The incremental costs from an investment bias are likely to be dwarfed by the risks that result from underinvestment in new facilities and degradation to existing assets. (Envestra, sub. 22, p. 22)

> 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. (NECG 2001, p. 16)

Asymmetric truncation

There are at least two ways in which asymmetric truncation could occur under the Gas Access Regime:

- *recontracting* — at an access arrangement review, regulators require reference tariffs to be revised downwards to reflect recent high profits (sometimes referred to as a lack of regulator commitment to the 'regulatory contract' made with a regulated business)
- *benefit sharing mechanisms* — rules are specified in advance in an access arrangement that oblige a service provider to redistribute some, or all, of a better than expected profit to users.

Benefit sharing rules can provide some certainty about how profits will be asymmetrically truncated, provided the rules are well specified and cannot be readily changed by a regulator. In contrast, recontracting can introduce an additional source of regulatory risk.

The existence of recontracting and benefit sharing does not prove that the distribution of competitive profits is asymmetrically truncated. That depends on the profit level and timing at which truncation commences. It is possible that recontracting and benefit sharing are only used to mimic a competitive market's tendency to redistribute productivity gains to users over time. They could also be restricted to curtailing high monopoly profits. Hence, the key concern is whether the profit level and timing at which truncation commences redistributes efficiency gains to users at a faster rate than would be expected by a competitive service provider.

The Victorian Essential Services Commission (ESC) described the tradeoffs involved in transferring efficiency gains to users:

> In addition to encouraging efficient behaviour by monopoly businesses, regulators must also try to ensure that customers share in the benefits of realised efficiency gains. But transferring benefits to customers reduces companies' incentives to undertake actions that lead to efficiency gains in the first place. Regulators therefore face another tradeoff in trying to create incentives for utilities to behave efficiently, while ensuring that customers share in benefits from efficiency gains. Laffont and Tirole [(2000), *Competition in Telecommunications*, MIT Press, Cambridge Massachusetts, p.41] refer to this as the 'rent and efficiency tradeoff'. Optimising this tradeoff is also central to regulation. (sub. DR112, p. 7)

In their landmark book on investment under uncertainty, Dixit and Pindyck (1994) demonstrated that, even in a competitive market, prices can be above costs for an extended period. As a result, there is a danger that a short-term comparison of prices and costs at an access arrangement review could be misinterpreted by regulators as evidence of monopolistic behaviour:

> The natural competitive dynamics of an industry in the face of ongoing uncertainty will have phases when a 'snapshot' of the industry has features that the static [economic] theory would interpret as deviations from competitive behaviour. … Suppose such an industry comes to the attention of policy authorities at an instant when the price is between the Marshallian long-run level [long-run average cost] … and the equilibrium threshold [price that is above cost and at which new firms enter the market under industrywide uncertainty] ... They see established firms making supernormal profits, but no new entry taking place. Using conventional microeconomics or industrial organisation theory, they would suspect the presence of monopoly power or entry barriers, and might take antitrust action. That would be wrong; the process viewed as a whole is fully competitive, long-run expected returns are normal, and the equilibrium is socially optimal. (Dixit and Pindyck 1994, pp. 292–3)

Biglaiser and Ma (1999) also noted the adverse impact of recontracting on investment:

> The incentive to invest *ex ante* may be reduced or become absent altogether because the returns of a sunk investment cannot be guaranteed due to the lack of [regulator] commitment. The commitment problem is especially critical in a deregulatory environment, in which regulators may be charged with the responsibility of promoting competition, and tempted to reduce the regulated firm's price after it has made the investment. (Biglaiser and Ma 1999, p. 216)

Possible reasons why a regulator would asymmetrically truncate profits are summarised in box 4.4. With respect to an asymmetry in observing regulatory errors, Gans and King (2004) observed:

> … a regulator, who sets an access price after the relevant investment is sunk, has a strong social incentive to set a low access price. Such an access price will promote efficient use of the facility, competition and social welfare without deterring the investment that has already occurred. (Gans and King 2004, p. 2)

A regulator's mistrust of regulated businesses might also cause it to mistakenly interpret high profits as evidence of monopolistic behaviour, rather than better than expected returns by businesses that behave competitively. Such mistrust could be based on a regulator's perception that businesses try to mislead regulators by withholding or distorting information. The ACCC noted:

> ... whether regulators are encouraged to expropriate rents or not, producers may be able to 'game' regulators to achieve required rates of return. For example, Besanko and Spulber (1992) ['Sequential-equilibrium investment by regulated firms', *Rand Journal of Economics*, vol. 23, no. 3, pp. 153–70] demonstrate how firms can use information asymmetry to influence the price set by regulators. Likewise, Spiegel and Spulber (1994) ['The capital structure of a regulated firm', *Rand Journal of Economics*, vol. 25, no. 3, pp. 424–40] demonstrate that a firm can choose its capital structure to influence the rates of return set by regulators. (ACCC, sub. DR101, p. 65)

It is notable that some regulators under the Gas Access Regime have expressed concerns about an information asymmetry with service providers and as a result have sought to expand regulators' information collection powers (chapter 7).

Gans and King (2003) noted that regulators might have a tendency to asymmetrically truncate because projects with high returns are more likely to be regulated:

> If the project is highly successful, regulatory access most likely will be sought. Even if regulators allow investors a 'reasonable rate of return' in these circumstances, unless this return fully compensates investors for the *ex ante* risk associated with project failure, access regulation will mute investment incentives. Put simply, investors will bear all the downside risk of the investment and face a truncated upside return due to access regulation. (Gans and King 2003, p. 1)

Another reason why asymmetric truncation is possible is that a regulator might fail to take account of uncertain fluctuations in demand. Such fluctuations, both short and long term, are likely for gas pipelines. One source of short-term uncertainty is fluctuations in the weather. For example, demand for gas heating might be higher than expected in an unusually cold winter, leading to better than forecast returns. An example of long-term demand uncertainty would be changes in gas consumption from a pipeline servicing mining activities. The output of the mining sector is subject to many factors, including world prices, exchange rates and mineral discoveries. A pipeline servicing mines might therefore have periods of high demand, periods of low demand, and there is a risk of mine closure.

Possible consequences for pipeline investment

If regulatory risk, asymmetric truncation or regulatory error reduce expected profits and/or increase risk, then some riskier projects might no longer have an expected profit that investors consider is sufficient to compensate for the associated risk. Investors could respond by abandoning such projects. Alternatively, investors could modify projects so they are unlikely to be regulated (enabling a higher expected rate of return than allowed by regulators) or are lower risk (to match the low expected rate of return allowed by regulators). Relative to the intended outcome under cost-based price regulation, this might involve greater emphasis on:

- *building capacity that is essentially fully contracted* — pipelines are smaller in diameter than otherwise because capacity is essentially built exclusively for clients that enter a long-term contract before construction
- *incremental expansion* — greater reliance than otherwise on expanding capacity incrementally to meet demand growth as it arises, rather than building a larger pipeline initially based on forecasts of realisable demand
- *delaying investment* — new projects are delayed for longer than otherwise while investors wait until demand is more certain.

Thus, regulatory risk, regulatory error and asymmetric truncation have the potential to distort not only the level of investment but also its timing, thereby favouring less risky projects. Investors in regulated pipelines will proceed only with projects that deliver the relatively low expected rate of return allowed by a regulator if those projects are also low risk. A distortion thus arises because some risky projects, which have the potential to generate economywide benefits, do not proceed as early as they might have otherwise. Similar observations were made by Kolbe, Tye and Myers (1993) and Train (1991):

> Failure [by regulators] to account explicitly for regulatory and other asymmetric risk will usher in a new era of an undercapitalised public utility sector. Regulated firms will have strong incentives to deter investment and utilise small scale technology that is below minimum efficient scale. (Kolbe, Tye and Myers 1993, p. 60)

> … if competition creates downside risks and tight rate of return regulation eliminates profits above the cost of capital, then pipelines cannot earn fair profits on average. Consequently, investment in the natural gas pipeline industry will eventually be retarded and biased towards safe activities. Risky investments necessary to provide reliable service will be discouraged. (Kolbe, Tye and Myers 1993, p. 139)

> … asymmetric treatment of uncertainty — by which losses by the firm are treated differently by the regulator than extraordinary profits — leads to distortions in the firm's actions that operate against optimality … asymmetry can actually induce the firm to make decisions in a way that ultimately works against the goals of the regulator and the welfare of customers. (Train 1991, pp. 96–7)

The impact of cost-based price regulation on infrastructure investment can have important implications for parties in upstream and downstream markets. For example, less investment in greenfield gas pipelines could harm existing or potential upstream producers that would have benefited from access to a new market, or potential downstream users that are denied gas. Similarly, distorting investment in existing pipelines — extensions, expansions and maintenance — could adversely affect upstream and downstream users.

In summary, cost-based price regulation has the theoretical potential to increase investment efficiency in industries that use a natural monopoly technology, but it is difficult to fully realise that potential in practice. As the extent of regulatory error, regulatory risk and asymmetric truncation increase, any improvement that cost-based price regulation makes to investment efficiency will tend to fall. Cost-based price regulation might even reduce investment efficiency, particularly where the theoretical benefits of regulation are modest relative to the practical problems of regulatory error, regulatory risk and asymmetric truncation. For this reason, it might be prudent to restrict cost-based price regulation to cases where there is clear evidence of considerable monopoly power:

> … inherent limitations [of regulation] create a tradeoff between regulators' attempts to replicate the efficient behaviour and outcomes of a competitive market and the regulatory costs that are incurred through these efforts. In some circumstances, the regulatory costs incurred in pursuing a more efficient outcome may outweigh the potential benefits that are available. These potential benefits depend on the extent of the firm's monopoly power, the materiality of the regulated services in related markets, and the extent of the resource misallocation that would result from unregulated monopoly supply. (ESC, sub. DR112, p. 7)

4.5 Impact on pipeline investment — the evidence

The conceptual framework outlined in the previous section indicates that the Gas Access Regime's cost-based price regulation is more likely to improve the efficiency of pipeline investment when:

- there is considerable monopoly power
- there is little, if any, regulatory error, regulatory risk, or asymmetric truncation.

The extent to which gas pipelines have monopoly power is considered elsewhere in this report. In particular, chapter 2 found that gas pipelines do have natural monopoly characteristics, but their market power might be constrained by various factors.

This section investigates whether there is evidence of regulatory error, regulatory risk, or asymmetric truncation under the Gas Access Regime. Evidence of the resulting distortion to investment is also investigated:

- deferred investment (new projects are delayed for longer than otherwise, including permanently)
- a shift to lower risk projects (greater emphasis on building capacity that is essentially fully contracted, and increased use of incremental expansions)

However, evidence of distorted investment can be difficult to identify, since it is hard to know what investment would have occurred without the Gas Access Regime. For example, growing gas demand might have caused pipeline investment to increase regardless of the regime. Examining evidence of regulatory error, regulatory risk, and asymmetric truncation provides a way of separating the effects of the regime from other determinants of investment.

Evidence of regulatory error

Regulatory error could occur with respect to:

- coverage decisions
- the terms of regulated third party access.

The Commission's assessment — detailed in chapter 6 — is that the Gas Access Regime's coverage test sets too low a threshold for cost-based price regulation. That is, coverage decisions could involve the regulatory error of applying cost-based price regulation when its costs outweigh its benefits, including with respect to investment.

Where price regulation is warranted, the Commission's assessment — detailed in chapter 7 — is that there is high potential for regulated prices to incorporate regulatory errors that reduce expected returns. This is attributable to the combination of a number of factors:

- There are many complex issues — and hence scope for errors — associated with calculating a regulated price that is designed to just cover expected costs.
- Regulators have to make subjective judgments about risk, given that investment returns are uncertain. For example, regulators periodically assess service providers' forecasts of future demand and efficiency gains, and in some cases have required them to be amended. This necessarily requires regulators to use debatable assumptions, given that the future cannot be known with certainty.

- A regulator's subjective judgment of risk could differ from that of the business it regulates. A regulator might apply the rules correctly based on its judgment, but this is not the judgment held by the business whose behaviour it is trying to influence. It must be remembered that businesses make investment decisions, not regulators. As the ESC noted:

  > Regulators must be cognisant of investors' risk perceptions since these will influence the amount of investment that takes place in the industry, as well as the terms on which investors are willing to provide capital. (sub. DR112, p. 8)

- Appeal decisions have identified errors made by regulators in setting reference tariffs (*Application by Epic Energy South Australia Pty Ltd* (2003) ACompT 5; and *Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6). Such regulatory errors have tended to impose lower regulated prices than otherwise.
- Economics provides little guidance on how to set efficient prices in imperfectly competitive markets, such as those that are evolving for gas pipelines in eastern Australia (section 4.7).

Evidence of regulatory risk

There is a potential for regulatory risk under the Gas Access Regime because of its complexity and the discretion given to regulators to handle this complexity. Such risk might result in service providers and access seekers having different expectations about regulatory outcomes. Because regulators cannot satisfy all expectations, over time some parties might lack confidence in the system (that is, in the regulatory regime, not necessarily the regulatory organisations). As noted by the ESC:

> … excessive discretion or the inappropriate exercise of discretion can increase uncertainty and regulatory risk which can in turn increase the cost of capital, or prevent companies from undertaking investments or initiatives that would otherwise improve efficiency. (sub. DR112, p. 8)

This section examines the evidence on various possible sources of regulatory risk under the regime.

Coverage risk

The Gas Access Regime's cost-based price regulation can only be applied to covered pipelines. A new pipeline will become covered if one of the following occurs:

- the relevant Minister, following a recommendation from the National Competition Council (NCC), decides the pipeline should be covered

- a competitive tender process is undertaken in accordance with ss3.21–3.36 of the Gas Code
- the service provider volunteers to be subject to the regime.

Ministers cannot make coverage decisions for proposed pipelines. Thus, if investors want to eliminate uncertainty about whether their proposed pipeline would be regulated, then they have to volunteer to subject it to the regime (possibly via a competitive tender process). In doing so, investors can reach an upfront agreement with a regulator about the details of their access arrangement (chapter 9).

However, investors are unlikely to volunteer to be subject to cost-based price regulation, given the many concerns expressed by service providers about the costs of the regime (for example, sections 4.8–4.9 below and chapter 7). Indeed, many owners of existing pipelines have applied to have their coverage revoked (table C.4).

The ACCC argued that coverage risk is low for new pipelines because they are unlikely to meet the coverage criteria:

> … coverage under the Gas Access Regime only applies to pipelines that satisfy the criteria in section 1.9 of the [Gas] Code. For many new pipelines, there is little prospect that these conditions will be met and it is therefore unlikely that they will be covered. … Further service providers may face incentives to restrain their exercise of market power for a time in order to develop new markets. This was evident in the case of the Eastern Gas Pipeline (EGP). The Australian Competition Tribunal … was 'not satisfied that coverage would promote competition in the regional markets over the existing access terms and conditions'. (sub. DR101, p. 14)

Nevertheless, the Commission considers that the regime subjects most, if not all, new pipelines to coverage risk. That is, a lack of certainty about whether a proposed pipeline would be subject to third party access regulation and, if so, when. As mentioned in chapter 3, the process of making a coverage decision can be initiated at any time by a party lodging an application with the NCC. Envestra noted the risk this uncertainty presents:

> A problem with the current [Gas] Code in relation to coverage is that any person can apply to have a pipeline or network covered (or uncovered) at any time. This requirement generates some uncertainty about the length of time for which an uncovered pipeline would remain uncovered. This is a source of regulatory risk which may have a chilling effect on investment. (sub. 22, p. 23)

The Study of Gas in Northeastern New South Wales observed:

> Under the Gas Access Regime as it presently exists, the risk that gas infrastructure might be subjected to regulatory coverage is not one that can be avoided or managed. An infrastructure owner can exert no control over the coverage decision making

> process. Accordingly, the implications of regulatory coverage, however uncertain they may be, need to be contemplated and taken into account when making a commitment to proceed with a project. (sub. DR79, p. 4)

Parameter risk

The Gas Code provides considerable flexibility about how key regulatory parameters — such as for depreciation and the rate of return on capital — are determined (chapter 7). This enables regulators and service providers to avoid a one-size-fits-all approach to how reference tariffs are determined. However, the flexibility provided by the Gas Code also leads to parameter risk. That is, investors cannot be certain about what parameters regulators will consider to be appropriate and whether this will change over time.

For example, Envestra noted that, between 1998 and 2003, the regulator of its Victorian distribution network changed the way regulatory parameters had to be determined:

> The methodology used by the Victorian Essential Services Commission in the 2003 access arrangement review is different to that used in its 1998 process and significantly reduces the dollar value of each distributor's return on assets by up to $2m per annum. This change in approach was not anticipated by the regulated businesses … (sub. 22, p. 11)

In particular, Envestra noted there was a change in how the *ex ante* regulatory rate of return was calculated:

> The first access arrangements were based on a real pre-tax WACC [weighted average cost of capital]. With the evolution of the regime, regulators are gradually changing their approach and imposing a post-tax WACC on distributors … As a consequence the margin over risk-free rates has declined and returns to businesses have been reduced. (sub. 22, p. 11)

Similarly, the ACCC (2002b) changed the beta parameter (a measure of investment risk) used to calculate the *ex ante* regulatory rate of return for GasNet's Victorian transmission system. GasNet noted:

> … the ACCC shifted the GasNet equity beta from 1.2 to 1.0 between 1998 and 2003. (sub. 47, p. 6)

The ACCC acknowledged its discretion in approving betas:

> … generally we have adopted an equity beta of around one, usually a little bit more than one … yet there is ample discretion for us to go much lower than that. (trans., p. 338)

GasNet appealed to the Australian Competition Tribunal on several matters of the access arrangement that the ACCC drafted and approved. In relation to the equity beta parameter, the ACCC noted:

> … in a current [now finalised Australian Competition] Tribunal matter — the GasNet decision … we've got some material provided by the Allen Consulting Group suggesting that the [equity] beta measure, based on market evidence, is around the 0.7 or 0.75 mark. There's good evidence for us to rely on, if we wanted to go there, but we take a cautious approach and we've adopted an average equity beta. … As soon as we put in our submission [to the Tribunal] that, 'well, we were generous and it is open to the Tribunal to come to a lower view if it chooses to', [GasNet] withdrew that issue from their statement of claim. (trans., p. 338)

However, the Australian Competition Tribunal did find that the ACCC had made errors with respect to other parameters, including the bond rate used to calculate the *ex ante* regulatory rate of return (*Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6).

More generally, GasNet observed:

> The [Gas] Code imposes an additional layer of regulatory risk on top of those risks already present in pipeline development (this applies both to expansion of the existing system and to greenfields developments). The way in which the current Gas Code is applied by regulators has a 'chilling' effect on new investment. (sub. 47, p. 3)

Epic Energy, commenting on the ACCC's final decision for the Moomba–Adelaide pipeline, noted:

> 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. This will lead to the development of an inefficient pipeline network which is not in the long-term public interest. (Epic Energy 2001, p. 1)

The Northern Territory Treasury observed:

> … the current [Gas] Code can be enforced in a manner which could generate a significant degree of regulatory uncertainty for future investors in the [Northern] Territory. This uncertainty presents a significant disincentive to new pipeline investment as well as distorting pipeline investment decisions. (sub. 41, p. 2)

The Network Economics Consulting Group was critical of regulators' inconsistently chosen values of the weighted average cost of capital (WACC), beta and other parameters. It suggested this source of regulatory risk could be reduced:

> WACC has been, and continues to be, an especially contentious part of the Australian regulatory environment. To some extent, this is not surprising given the inherently uncertain nature of the WACC. Regulators have selectively exploited this uncertainty

> in choosing particular parameter values, with the treatment of the risk free rate, asset beta, debt beta and the market risk premium especially contentious … While uncertainty will continue to be a feature of the WACC, we believe that a framework for the WACC can be developed that will reduce uncertainty over regulated WACC allowances. (sub. 56, pp. 7–8)

Concerns were also expressed about changes in benefit sharing mechanisms over time. The ACCC described a benefit sharing mechanism as involving:

> … a methodology for the sharing of greater than expected revenues between the service provider and users, and [that] may also identify an event that will invoke the benefit sharing provisions. (sub. 48, p. 52)

Benefit sharing rules can reduce uncertainty if they are well specified and cannot be readily changed by a regulator. However, some inquiry participants observed that regulators have required changes to benefit sharing mechanisms at access arrangement reviews and this has increased uncertainty. For example, Envestra noted that the ESC (2002b) changed the way in which benefits are shared for Victorian distribution networks. Envestra (sub. 22, p. 11) claimed that ‘expectations at the time of approval of access arrangements were that efficiency gains would be shared equally (50:50)’, but an ‘efficiency sharing methodology that only allows businesses to retain 30 per cent of any efficiency benefits achieved’ has since been implemented.

Similarly, the AGA noted an inconsistent approach across jurisdictions to the sharing of efficiency gains, which provides little certainty for new investors:

> ... the treatment of unforecast efficiency gains, including the sharing of gains and whether unforecast efficiency gains may be shared across regulatory periods has been subject to widely varying approaches between different regulatory authorities. (sub. 13, p. 57)

This flexibility might reduce the incentive for service providers to ‘game’ their expected demand forecasts, because there could be an:

> … adverse outcome for the service provider by lowering the benefit sharing threshold point. (ACCC, sub. 48, p. 52)

Asset stranding/redundant capital

Investors face the risk that, if their pipeline becomes covered under the Gas Access Regime, then part of their investment will subsequently be declared redundant because it does not contribute to the delivery of services. If this occurs, then the capital base used to determine regulated prices will be reduced and, other things being equal, reference tariffs will fall.

A practical example under the Gas Access Regime was the requirement in the ACCC's final decision for the Moomba–Sydney pipeline that there be an amendment to the service provider's reference tariff policy to:

> … allow the [Australian Competition and Consumer] Commission, at the commencement of the subsequent access arrangement period, to review and, if necessary, adjust the capital base for wholly or partially redundant assets. (ACCC 2003b, p. 85)

The ACCC noted this requirement was intended to:

> … reduce uncertainty and ensure that users do not pay for assets that have ceased, or have substantially ceased, to contribute to the delivery of services. (ACCC 2003b, p. 85)

The Gas Code (s.8.27) requires the risk of assets being made redundant to be recognised in determining the *ex ante* regulatory rate of return and the economic life of assets. A practical example is the risk premium that IPART (2000) allowed in the *ex ante* regulatory rate of return for AGL's distribution network in New South Wales to compensate for the possibility of capital redundancy:

> The prospects of assets becoming stranded and the associated risks has been taken into account in determining the rate of return. (IPART 2000, p. 92)

However, the Gas Code does not specify how a rate of return or asset life should be adjusted to reflect the possibility of asset stranding. That is, there is still regulatory risk associated with asset stranding, despite the requirements of the Gas Code. Kolbe and Tye (1992) demonstrated that it is difficult to determine the appropriate adjustment to an allowed rate of return to compensate for the risk of asset stranding.

The AGA noted:

> The current Gas Access Regime provides insufficient upfront certainty for a range of capital and noncapital investments made by investors and owners of regulated gas network and pipeline assets. This leaves asset owners and potential investors subject to significant, unnecessary, and uncompensated regulatory risk, in particular, the risk of cost optimisation of prudent investments in future regulatory reviews. (sub. 13, p. 68)

Transfer of risk from foundation customers

Foundation customers have a fundamental role in the development of pipelines because they often enable service providers to share risk with their customers. This risk sharing can involve a commitment by foundation customers to purchase specific transport capacity for delivery of gas at a certain price and/or to partially finance the pipeline.

The ACCC claimed that foundation customers also reduce the potential for the Gas Access Regime to discourage investment because foundation contracts:

> … cap the possible downside risks and increase the *ex ante* expected average rate of return. (sub. 48, p. 60)

However, the tariffs approved by a regulator for third party access — reference tariffs — could be less than the prices agreed to by foundation customers:

> It is possible that reference tariffs established for a covered pipeline might be lower than those that have been adopted in foundation user agreements, and below those relied upon in committing to the pipeline investment. Such an outcome would have a destabilising impact upon the commercial operations of the pipeline with possible erosion of returns from levels envisaged at the time of commitment to construction of the pipeline. (ACCC, sub. DR101, appendix E prepared by Sleeman Consulting, p. 12)

If reference tariffs are lower than foundation prices, then foundation customers face the prospect that their (non-foundation) competitors will transport gas at a lower price. This gives foundation customers a strong incentive to include 'most favoured nation' clauses in their contracts with service providers. Such clauses oblige a service provider to charge no more than the lowest price offered to other users of a given service.

Most favoured nation clauses have the effect of transferring risk from foundation customers to service providers. ExxonMobil noted the adverse effect this might have on investment:

> To mitigate this risk [that regulated third party tariffs are set lower than the negotiated foundation customer tariff], a foundation shipper may endeavour to negotiate matching rights, although this then places the regulatory risk on the pipeline developer and may lead to the pipeline either being built with no spare capacity or worse, not being built at all. (sub. 8, p. 5)

In contrast, the ACCC claimed that most favoured nation clauses could promote investment:

> Foundation contracts are designed to guarantee a level of revenue on a new pipeline for a fixed period of time. If market growth is rapid and there is substantial utilisation of the pipeline by new shippers, revenue may increase and average costs may decline on the pipeline.
>
> In these circumstances, the sharing of 'blue sky' is in the interests of both foundation shippers (which bear most of the risk of the pipeline) and the pipeline developer and can serve to promote investment in pipelines that may otherwise be deferred. The 'most favoured nation' (MFN) clause can be viewed in this light given that the best outcome may be achieved by the pipeline company reducing prices to later customers to achieve optimal utilisation of the pipeline and maximise revenue. Therefore, it should not be assumed that MFN clauses were never intended to be invoked. Also, access arrangements should not be constrained, as a matter of course, to avoid these clauses

from being invoked as it may engage an anticipated position by both pipeline owners and users.

Nevertheless, the ACCC has always taken a cautious approach when it is advised of the existence of foundation contracts with an MFN clause. (sub. DR101, p. 20)

WMC Resources implied that most favoured nation clauses might be used regardless of the Gas Access Regime:

… given the risks which foundation shippers carry, WMC believes it is logical that they would seek to negotiate a ‘favoured nation’ status in their contracts to ensure they are not disadvantaged by future development of the pipeline. This recognises the fact that pipeline unit costs generally decrease in real terms as throughput increases toward pipeline capacity. Without the ‘favoured nation’ status, the foundation customer is faced with the possibility that competitors will benefit from a lower tariff despite the competitor taking none of the risk associated with the development of the pipeline. (sub. DR99, p. 9)

Evidence of asymmetric truncation

Service providers and their industry associations argued that asymmetric truncation does occur under the Gas Access Regime, for both existing and greenfield assets:

… once regulation is injected into the equation, businesses are not offered the ability to earn higher rates of return on some projects due to the tendency of regulators to cap rates of return at the economically efficient level, as determined by the regulator. This gives rise to regulatory [asymmetric] truncation at the efficient rate of return. Regulators have not adopted suitable measures to allow service providers to share sufficiently in the upside risk of successful projects in order to compensate for the downside losses. (Duke Energy International, sub. 21, p. 10)

The weaknesses of the current [Gas Access] Regime in dealing with greenfields projects include … the exposure of greenfields projects to ‘asymmetric’ regulatory risk — where the potential upside of a project is effectively capped by access regulation, but the downside risks of project failure remain borne entirely by the investor. (AGA, sub. 13, p. 60)

However, whether asymmetric truncation has been a problem in practice depends on a range of factors, which are discussed below.

Is truncation just a theoretical curiosity?

A key issue in assessing the efficiency effects of asymmetric truncation is whether such truncation has occurred within the expected range of competitive profits. This is because asymmetric truncation is more likely to reduce investment efficiency when it changes the expected profit distribution of a business that behaves competitively. Competitive behaviour might be attributable to the discipline of cost-based price regulation — as implied by s.8.1(b) of the Gas Code — or occur because a competitive business is mistakenly regulated. If asymmetric truncation only curtails high monopoly profits, then it is less likely to reduce efficiency.

The Allen Consulting Group claimed that, while asymmetric truncation might be a theoretical possibility, it is not a significant problem in practice because gas pipelines have a narrow distribution of possible returns:

> 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 ... 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 [Gas] 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. (BHP Billiton, sub. 26, attachment, pp. 18–19)

Similarly, the ACCC (2002a) implied that gas pipelines have a very narrow distribution of possible returns. In particular, appendix 3 of the ACCC's draft greenfields guideline provides an example where the standard deviation of expected sales is such that the rate of return on assets will tend to lie within 2 percentage points of 8 per cent.

The Commission is not convinced that the distribution of possible returns for gas pipelines is as narrow as claimed by the Allen Consulting Group and implied in the ACCC's draft greenfields guideline. To illustrate, appendix B presents a numerical example based on the parameters that regulators have applied to regulate gas pipelines. The results suggest that the distribution of possible returns for pipelines is much wider than asserted by the Allen Consulting Group and implied in the ACCC's draft greenfields guideline (figure B.2). In other words, an actual rate of return significantly above that expected by a regulator could be consistent with a pipeline that behaves competitively. If competitive returns are as widely dispersed as the example suggests, then regulators will find it extremely difficult to distinguish between a competitive pipeline that experiences a better than expected outcome and a pipeline that is exerting market power. In other words, it will be hard for regulators to avoid asymmetrically truncating competitive returns.

The ACCC acknowledged the possibility of asymmetric truncation, but claimed this might be mitigated by features of the gas industry and the Gas Access Regime:

> … there are several factors that substantially mitigate the possibility of a 'truncation problem' in the gas pipeline industry. First, pipelines must pass an initial screening process before they are subjected to regulation. Pipelines that do not possess market power are unlikely to be regulated. Moreover, downside risks are truncated for most

> new pipelines by foundation contracts which guarantee a minimum level of volume and revenue. (sub. 48, p. xiii)

However, the Gas Access Regime is supposed to be applied with a view to replicating the outcome of a competitive market (s.8.1(b) of the Gas Code). If regulators are meeting this requirement, then it is reasonable to expect that regulated businesses are behaving competitively. In other words, cost-based price regulation should result in a profit distribution that approximates that of a competitive service provider. If asymmetric truncation occurs under such circumstances, then it will tend to truncate a competitive profit distribution.

In addition, the Gas Access Regime provides an incentive for foundation customers to include most favoured nation clauses in their contracts (refer to above discussion on regulatory risk). The behaviour of foundation customers under cost-based price regulation could therefore exacerbate downside risk, rather than curtailing it as suggested by the ACCC.

The Energy Markets Reform Forum suggested asymmetric truncation is not a problem in practice because the nature of pipeline investments (especially extensions) means returns are averaged over time:

> … access regulation operate[s] over a system, and losses or supernormal profits can be pooled against the starting base regulated revenues. If there is a loss on the extension, that shows up as a reduced systemwide rate of return and allows price increases within the allowed rate of return. If there is a supernormal profit on the extension, it gets pooled with returns from the existing capital base and is only clawed back in a later regulatory review if the extension lifts the returns over the whole system past the allowed rate of return. That is as it should be — supernormal returns averaged over time over projects are evidence not of a return to capital but of rents attributable to the underlying franchise. (sub. 30, p. 28)

The Commission considers that returns cannot be averaged over time for all investments. Some investments never have the opportunity to earn high returns and therefore cannot offset below average returns. Further, this argument assumes service providers can cross-subsidise on returns. This might not always be the case and particularly so with structural reform taking place and emerging competition in the gas industry.

Recontracting at access arrangement reviews

One of the key functions of an access arrangement review is to ensure that reference tariffs do not diverge significantly from costs over time. In particular, the Gas Code requires reference tariffs to be periodically reviewed so they reflect the most recent expectations of future demand and efficient costs. The role of access arrangement reviews is evident in s.3.18 of the Gas Code, which requires regulators to consider the adoption of 'safeguard' mechanisms when an access arrangement period of more than five years is approved:

> An Access Arrangement Period accepted by the Relevant Regulator may be of any length; however, if the Access Arrangement Period is more than five years, the Relevant Regulator must not approve the Access Arrangement without considering whether mechanisms should be included to address the risk of forecasts on which the terms of the Access Arrangement were based and approved proving incorrect. These mechanisms may include:
>
> (a) requiring the Service Provider to submit revisions to the Access Arrangement prior to the Revisions Submission Date if certain events occur, for example:
>
> (i) if a Service Provider's profits derived from a Covered Pipeline are outside a specified range or if the value of Services reserved in contracts with Users are outside a specified range;
>
> (ii) if the type or mix of Services changes in a certain way; or
>
> (b) a Service Provider returning some or all revenue or profits in excess of a certain amount to Users, whether in the form of lower charges or some other form.
>
> Where a mechanism is included in an Access Arrangement pursuant to section 3.18(a), the Relevant Regulator must investigate no less frequently than once every five years whether a review event identified in the mechanism has occurred. (Gas Code, s.3.18)

Recontracting at an access arrangement review could be used to maintain the viability of a service provider when unforseen adverse changes in market conditions or government policy occur. This would truncate downside risk. However, there is also potential for reference tariffs to be revised downwards when recent revenues are above costs, thus limiting the scope to keep upside profits.

At the time of writing this report, only three access arrangement reviews had been completed:

- New South Wales distribution (AGL Gas Networks) in 2000
- Victorian and Albury distribution (Envestra, Multinet and TXU) in 2002
- Victorian transmission (GasNet) in 2003.

In its access arrangement review for New South Wales distribution, the Independent Pricing and Regulatory Tribunal (IPART) noted that, among other things, it took account of the service provider's recent performance:

> In accordance with the objectives and requirements of the [Gas] Code, the Tribunal has adopted a process which involves:
>
> - assessing operational and capital expenditure
> - analysing financial indicators, including the rate of return and assessing the service provider's past, current and future commercial performance

- considering the impact on consumers and service standards
- providing appropriate signals for efficient new investments
- implementing incentive based regulation to encourage ongoing efficiency gains by the network service provider, thereby ultimately delivering lower prices to customers
- enhancing economic efficiency and competition (including upstream and downstream competition). (IPART 2000, pp. 48–9)

IPART approved tariffs on the basis that the expected net present value of revenues and costs were to be equal during the access arrangement period (after allowing for a 'transitional charge' of $12 million in 2000-01). To achieve this, tariffs were revised downwards in real terms from 2001-02 to 2003-04 using a CPI minus 1 per cent price cap.

Similarly, the ACCC (2002b) and ESC (2002b) approved revised access arrangements for Victorian transmission and distribution systems respectively using a cost of service approach, which involved resetting total expected revenue at a level that recovered the expected cost of providing services. These expectations would have been conditioned by service providers' recent performance.

However, considering recent performance when formulating expectations of future returns does not necessarily lead to asymmetric truncation. For example, the ACCC (2002b) observed that GasNet's operation and maintenance costs in the five years before its access arrangement review were much lower than forecast. Nevertheless, the ACCC largely accepted GasNet's claim that this was due to one-off factors, rather than being evidence of ongoing cost reductions that could be repeated in the next access arrangement period:

> The [Australian Competition and Consumer] Commission considers that the operations and maintenance costs proposed by GasNet for the second period, subject to the amendments noted above, are not inappropriate. GasNet has provided detailed evidence quantifying and outlining the reasons for the increase in costs between the first and second period, and evidence suggests that these cost increases would be incurred by a prudent service provider acting efficiently (ACCC 2002b, p. 141)

In addition, the ACCC noted that the economic literature points to various ways of addressing investor concerns about recontracting by regulators:

> In the event that the regulator is unable to commit to a long-term regulatory contract, Greenwald (1984) ['Rate base selection and the structure of regulation', *Rand Journal of Economics*, vol. 15, no. 1, pp. 85–95] reasons that constraints can be placed upon a regulator's ability to expropriate rents *ex post*. Likewise, Salant and Woroch (1992) ['Trigger price regulation', *Rand Journal of Economics*, vol. 26, no. 3, pp. 362–77] argue that firms that can incrementally build up investment can punish regulators by refusing further investment. Thus, whether commitment is an issue for investment

> depends upon the particular regime and the incentives faced by regulators. Baron and Besanko (1987) ['Commitment and fairness in a dynamic regulatory relationship', *Review of Economic Studies*, vol. 54, no. 3, pp. 413–36] argue that in the absence of a long-term contract, a relationship based on fairness can arise. (ACCC, sub. DR101, pp. 64–5)

A practical example under the Gas Access Regime is the scope for regulators to use the fixed principle provisions of the Gas Code (ss8.47–8.48). Those provisions enable regulators to make a commitment not to revise regulatory parameters at an access arrangement review. This is limited to 'structural elements', which include the depreciation schedule and the assumed financing structure. The Commission's assessment — detailed in chapter 9 — is that the fixed principle provisions of the Gas Code do not, in isolation, address the problem of asymmetric truncation. This depends on how fixed principles are implemented in practice in conjunction with other aspects of the Gas Access Regime, given the wide discretion provided to regulators.

Benefit sharing mechanisms in access arrangements

Fraser (1998) demonstrated it is theoretically possible to design a profit sharing mechanism that does not distort investment. However, the information required to implement such a mechanism in practice is unlikely to exist. As a result, profit sharing rules have to be based on a subjective judgment about what is an appropriate method for sharing benefits.

IPART (2000) made a similar observation about the limitations of benefit sharing rules during its assessment of AGL Gas Networks' access arrangement for New South Wales distribution. In particular, IPART decided that it was inappropriate to adopt benefit sharing rules because subjective judgments were required to determine the threshold at which benefit sharing commences and the share of benefits transferred to users:

> It is difficult to set a level for a benefit sharing scheme which would not act as a disincentive to AGLGN [AGL Gas Networks] to pursue growth. The issue of where the scheme should start and what the 'shares' to AGLGN and users should be is largely subjective. On balance, the [Independent Pricing and Regulatory] Tribunal has decided not to require a benefit sharing scheme in the Access Arrangement. (IPART 2000, p. 201)

Nevertheless, benefit sharing rules have been approved by other regulators under the Gas Access Regime. For example, section 3.3.7 (Incentive Mechanism) of Envestra's access arrangement for the South Australian gas distribution network allows better than forecast efficiency gains to be retained by Envestra into the next access arrangement period:

(1) The full value of any efficiency gains, including reductions in the costs of providing Reference Services and any revenue from the sale of Reference Services greater than forecast, may be retained by Envestra. This applies during this Access Arrangement Period and the following Access Arrangement Period (two Access Arrangement Periods). The application of this Incentive Mechanism is subject to Envestra continuing to manage and operate the Network in accordance with accepted industry practice and any service standards prescribed by any relevant law or applicable regulatory instrument.

(2) At the completion of the first Access Arrangement Period estimates relevant to the efficiency gains for the previous period will be re-examined. At the completion of the re-examination process, if it is discovered that;

(i) all or a component of the actual efficiency gains achieved were the result of significant decreases in input prices that were reasonably foreseeable at the time that the estimates relevant to the efficiency gains were made, or

(ii) the actual efficiency gains achieved were based on excessive under-estimations of sales that were reasonably foreseeable as such at the time that the estimates relevant to the efficiency gains were made, then

the proposed estimates relating to efficiency gains for the following Access Arrangement Period may be adjusted accordingly by the Regulator (however the efficiency gains for the first Access Arrangement Period will still be retained by Envestra within the first Access Arrangement Period). (Envestra 2003, p. 10)

This mechanism introduces an element of regulatory risk, since it is up to the regulator to judge whether greater than forecast falls in input prices and/or increases in sales in the first access arrangement period were 'reasonably foreseeable'. Nevertheless, the above benefit sharing mechanism does not involve a particularly rapid transfer of efficiency gains to users.

The ACCC (sub. 48, p. 52) expressed a preference for benefit sharing rules to be included in access arrangements. This was evident in the access arrangement that the ACCC (2002b) approved for GasNet. In particular, s.7.2 (benefit sharing allowance) of the access arrangement allows GasNet to keep the benefits of lower than forecast operating costs for five years. Again, this does not appear to be an overly rapid transfer of benefits to users. However, the mechanism approved by the ACCC also requires GasNet to bear losses arising from greater than forecast operating costs for five years. This reduces the potential to limit downside risk via recontracting at the next access arrangement review.

The ESC (2002b) approved efficiency carryover mechanisms for Victorian distributors (Envestra, TXU, and Multinet) that allow the benefits of lower than forecast operating and capital costs to be maintained by service providers for five years. However, unlike the carryover mechanism approved by the ACCC (2002b) for GasNet, Victorian distributors are not obliged to carry forward the burden of higher than forecast costs beyond the next access arrangement review. The ESC decided that it would judge any accrued negative carryover amount on a case-by-case basis at the end of an access arrangement period.

In addition, Envestra (sub. 22, p. 38) commented that 'the QCA [Queensland Competition Authority] is in the process of developing an efficiency carryover mechanism for the Queensland [distribution] networks'.

The AGA (sub. 13, p. 55) claimed the benefit sharing arrangements approved by the ACCC and ESC allow service providers to keep 30 per cent of unforecast efficiency gains in net present value terms. The remaining 70 per cent are transferred to users. For South Australian distribution, the AGA claimed that 50 per cent of unforecast efficiency gains are kept by service providers, with the remainder redistributed to users.

As noted by IPART (2000), deciding what proportion of benefits should be transferred to users requires subjective judgments. That is, it is not possible to say objectively what is the appropriate proportion of benefits that should be transferred to users. Nevertheless, the sharing proportions cited by the AGA indicate that service providers are allowed to keep more than a trivial amount of unforecast reductions in average cost. Whether they are allowed to keep more or less than what a competitive service provider would expect is difficult to judge. However, if the Gas Access Regime does cause service providers to behave competitively — as envisaged by s.8.1(b) of the Gas Code — then the benefit sharing mechanisms examined above are more likely to truncate competitive profits and hence reduce efficiency.

Deferred investment

A difficulty in considering whether investment has been deferred as a result of the regime is that there is no way of establishing the 'no regulation' scenario:

> A general comment regarding the Gas Access Regime has been the absence of a counterfactual scenario to the situation the gas industry finds itself in today … It is noted that there has been (significant) investment in gas pipeline infrastructure since 1997 — whether or not there would have been substantially more investment without the access regime is difficult to assess. (Origin Energy, sub. 52, p. 2)
>
> … assessing the impact of the operation of the Gas Access Regime is an inherently complex task, given the lack of a counterfactual, the difficulty of separating out the impacts of other related gas market reforms ... (AGA, sub. 68, p. 6)

The long lived nature of pipeline investments means the absence of new pipeline investment might reflect the stage of the investment cycle rather than a regulatory distortion of investment. Many of the capital cities in Australia, for example, are serviced by older transmission pipelines and distribution networks, so new greenfield investment might not have been crucial in recent years. However, declining reserves of the Cooper–Eromanga basin — as an example of a traditional gas supply — might necessitate new transmission pipelines linking other gas fields (such as the North West Shelf) with the east Australian markets supplied by that basin. This change would result in the need for new large scale greenfield investments.

Many inquiry participants argued the Gas Code discourages pipeline investment:

> The current form of regulation acts as a real and serious constraint on a company's willingness to invest in new facilities, and on their ability to maintain the investments they have made. (Duke Energy International, sub. 61, attachment prepared by Julie Dill, p. 3)

> The [Gas Access] Regime … has hindered investment by truncating returns, focusing on short term price reductions and not compensating for business specific and regulatory risk. (Envestra, sub. 22, p. 37)

> The possibility for future investment to be deterred by an open access regime's inherent intrusion on the property rights of current pipelines' owners has been recognised elsewhere. For example, a research paper on the national competition policy provided to members of the Commonwealth Parliament in 1994 states: 'An obvious risk associated with the third party access proposals is that the granting of access rights might undermine the viability of long-term investment decisions by adding greater risks and uncertainty. As a result future investment in important infrastructure projects could be deterred'. (Enertrade, sub. 14, p. 6)

> AGL's experience with the Gas Access Regime demonstrates the potentially chilling effect that the regime has had on greenfields investment in both transmission and distribution. AGL is able to draw on its experience with greenfields investment prior to the implementation of the Gas Access Regime and to contrast this with its experience under the current regime. (AGL, sub. 32, p. 21)

> The only certain outcome for society and the economy from a continuation of the current approach will be the knowledge that monopoly rents have been avoided. In the absence of adequate incentives and rewards, the most likely result of continuing with current practice will be underinvestment, leading to reduced service and unmet demand in the longer term. (AGL, sub. 32, p. 5)

Commenting on the effect that cost-based price regulation can have on expansions to existing pipelines, APIA noted:

> One example [of regulation's chilling effect on investment] is the unwillingness of some infrastructure providers to continue to invest without customers funding an expansion of the pipeline. Whilst APIA acknowledges that the [Gas] Code provides a vehicle for customers to fund expansions, APIA submits that any reliance upon such a provision demonstrates the failure of the regulatory regime. Clearly, there is the investment hold-up such an approach is likely to induce (due to the lumpiness of

expansions relative to customer needs). However, additionally, the outcome represents a failure of the regulatory system in that the owner of the pipeline (the entity which should most efficiently fund expansions) responds to regulatory risk by passing it to customers who are relatively poorly placed to cost effectively perform the function of funding (and selling) pipeline capacity. (sub. 44, p. 38)

AGL provided an example of the long-term impacts of deferred investment:

> AGL has direct experience of such a sequence [underinvestment, leading to reduced service and unmet demand in the longer term] with the rundown of its gas network which occurred over several decades from the 1950s. In that case, the gross margins available in the business were squeezed by increasing input costs and government constraints on retail prices with the result that it was not viable to maintain a long-term perspective on the condition of the network. Prior to the introduction of natural gas, this customer base was shrinking, investment in the network declined, and many suburbs of Sydney did not have gas pipelines installed at the time they were developed. While the consequences of reduced investment in the gas networks are not immediate, by the 1980s, AGL faced the decision of whether to rehabilitate or abandon the assets. By that stage, AGL was able to justify a major reinvestment program on the strength of a rapidly growing gas market for natural gas. It would not be in the interests of customers or investors if a repeat of this cycle of underinvestment were to be triggered by an overly onerous regulatory regime. (sub. 32, p. 5)

The ACCC (sub. DR101, pp. 8–9) argued there is little evidence of the regime having led to deferred investment, given that a study it had commissioned from ACIL Tasman found significant excess capacity among pipelines serving most demand centres:

> ACIL Tasman's modelling of the Australian gas market indicates that over the next 10 years only limited capital expenditure on greenfield transmission pipelines will be required as most of the major demand centres have now access to significant quantities of reserve pipeline capacity. Notable exceptions include the South-West region of Western Australia and potential for Northern gas (Timor Sea or [Papua New Guinea]) entering the south-east market. (ACCC, sub. DR101, attachment H prepared by ACIL Tasman, p. 34)

Nevertheless, ACIL Tasman also observed:

> The potential impact of disincentives to investment should not … be lightly dismissed. Any loss or deferral of investment brought about through inappropriate implementation of access regulation could potentially have significant economic impacts and act counter to the basic objective of access regulation, which is to encourage increased competition within the relevant market area. There is scope in the medium to longer term for the scaling back of regulation of transmission networks if, through the development of new greenfield pipelines, competitive alternatives become more widely available to consumers. To the extent that access regulation creates disincentives for investment, this would delay the development of genuine competitive markets, and extend the period during which imperfect regulatory mechanisms need to be applied in

an attempt to mimic competitive market outcomes. (ACCC, sub. DR101, attachment H, pp. 33–4)

Some inquiry participants suggested there is a healthy investment climate in Australia because of the significant pipeline investment in recent years. Examples of new investments are listed in table 4.1.

Table 4.1 **New investment in gas pipelines in the past 10 years**

Pipeline	*Length (km)*	*State*	*Project completed*
Interconnect (NSW–Vic)	151	NSW–Vic	1998
Eastern Gas Pipeline	795	Vic–NSW	2000
Ballera–Mt Isa pipeline	840	Qld	1998
Central West Pipeline	255	NSW	1998
Mid West Pipeline	353	WA	1999
Cannington Spur Pipeline	100	Qld	1998
Roma–Brisbane pipeline (looping)	434	Qld	1997–2002
Berri–Mildura pipeline	190	NSW	1999
South West Pipeline	152	Vic	1999
Tasmanian Gas Pipeline	732	Vic–Tas	2002
Wagga–Tumut pipeline	65	NSW	2001
SEA Gas Pipeline	660	Vic–SA	2004
Burrup extension pipeline	24	WA	1998
Dampier–Bunbury pipeline (stage 3A)	Additional compression	WA	2000
Gladstone–Bundaberg pipeline	**na**	Qld	2000[a]
Mildura distribution network	**na**	NSW	1997[a]
Tasmanian Gas distribution project	**na**	Tas	2003[a]

[a] Date of commencement. **na** Not available.

Sources: AGA, sub. 13, p. 63; APIA, sub. 44, p. 98.

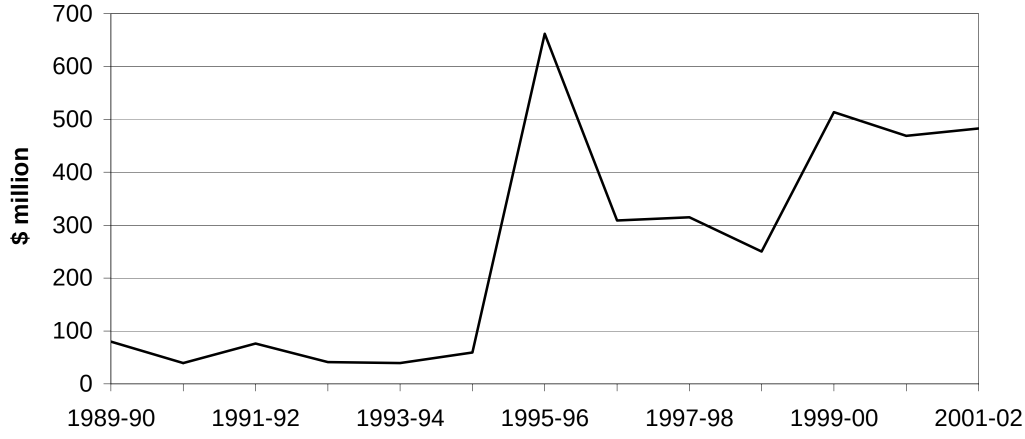
The ACCC (sub. 48, p. vi) provided a chart showing investment in transmission pipelines since 1989-90 (reproduced here as figure 4.2).

BHP Billiton (sub. 26, p. 29) stated that, during the period 1990-91 to 2001-02, ‘growth of capital expenditure in distribution networks increased by up to 15 per cent per annum’. BHP Billiton also argued:

> Far from facing a ‘distortion’ and ‘deterrence’ due to ‘regulatory uncertainty’, as portrayed in media statements by gas pipeline and network interests (and repeated in the [Productivity Commission’s] draft report), gas industry investments have outperformed the equity market. Over the past few years, Envestra, a company with relatively high exposure to the [Gas] Code has outperformed the Australian Pipeline Trust, which has less exposure by a healthy margin, and has outperformed the equity market by an even larger margin. In addition, we have shown that gas industry debt

issues have been oversubscribed. These are not the characteristics of an industry that is hampered by regulatory uncertainty. (sub. DR96, p. 24)

Figure 4.2 **Capital expenditure on transmission pipelines**



Source: ACCC, sub. 48, p. vi.

However, APIA noted that virtually all new transmission pipelines built since 1996 are not regulated under the Gas Access Regime:

> Investment in new transmission pipelines of well over $2 billion accounts for the vast majority of pipeline investment since 1996. Of the seven pipelines completed since 1996, only the $30 million CWP [Central West Pipeline] (a relatively minor pipeline that proceeded on the basis of direct government financial assistance) is regulated under the Gas Access Regime. That is, less than 2 per cent by value of new investment in transmission pipelines since the introduction of the Gas Access Regime is actually regulated under the Gas Access Regime, and arguably the investment decision in relation to the covered pipeline was affected by government assistance. Moreover, where investment faced the threat of regulation (as with the Goldfields pipeline), measures were taken to insure the pipeline owners against potential detriments. APIA believes that this clearly indicates the reality that the investment that has occurred over the last eight years has occurred in spite of the Gas Access Regime rather than because of it. As was elaborated upon in APIA's original submission, it is also further evidence that future development of capacity will occur on inefficient basis. (sub. 74, p. 14)

In contrast, the ACCC noted:

> There have been criticisms of the Gas Code as chilling investment in gas pipelines. We think that that criticism, by and large, has focused on rhetoric. There has been very little evidence to date put forward to substantiate those claims and, indeed, we think the evidence is quite the opposite, that there is substantial evidence of increased investment in gas pipelines in Australia since the Code was put in place and we don't think it's merely a coincidence. There can be a debate about the causal relationship between

> those two things but what is not in doubt is that that increase in investment in gas pipelines in Australia has occurred, as the Parer Committee [EMR 2002] recognised has occurred, in the context of the Gas Code being in place. (trans., p. 322)

In a more specific context, the Hunter Gas Users Group observed:

> The ACCC in its greenfields pipelines issues paper highlights that there has been continuing major investment in gas pipeline assets since the introduction of the Gas Code, with major ones being the Tasmanian Gas Pipeline, the SEA Gas Pipeline to SA and the NSW Central West system …
>
> The HUG [Hunter Gas Users Group] considers that there is no substance to the investments at risk due to intrusive regulation assertion about the implementation of the national Gas Access Regime and would argue against any dilution of Code provisions that protect consumer interests and seek a balance on the information and resource asymmetry problems faced by regulators and gas users. (sub. 4, p. 8)

Along the same line of reasoning, some inquiry participants claimed the failure of some projects to proceed was attributable to factors other than the regulatory environment. BHP Billiton and the Energy Markets Reform Forum cautioned against accepting claims about the chilling effect of regulation on investment without judging them against some objective criteria:

> … 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. (BHP Billiton, sub. 26, p. 21)
>
> It is important for the Productivity Commission to consider carefully the views of the pipeline industry with respect to its assertion that access regulation has deterred new investments. Invariably, the weaknesses of the current access regime are always cited as the reason for pipeline projects not going ahead, rather than the economic and commercial viability of the projects concerned. And whilst information is provided on the number of greenfield projects that have been cancelled, deterred or delayed during the period of the Gas Access Regime, little is provided in the public domain explaining that in most cases such projects have not proceeded due to commercial drivers. (Energy Markets Reform Forum, sub. 42, p. 5)

BHP Billiton provided specific information on why the deferral of many investment projects was not due to the Gas Access Regime. On the deferral of Epic Energy's proposed Darwin–Moomba project and ExxonMobil's proposed Papua New Guinea–Queensland project, it noted:

> 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. (sub. 26, p. 55)

However, ExxonMobil disagreed with BHP Billiton's assessment:

> … the PNG Highlands gas project (the PNG project) [Papua New Guinea–Queensland project] operated by ExxonMobil is currently seeking markets in eastern Australia and believes that it is offering a very competitively priced product. The project represents an enormous investment and its timing is dictated by the need to obtain synchronously sufficient volume commitments. To date, any market perceived delay to the PNG project has not been caused by the regulatory framework *per se*. However, as commented in our submission to the Commission on 28 August 2003, the inflexibility of the tender process to cater for redesign of pipeline routes as market opportunities develop, leads to an uncertain basis under which such a project moves forward. ExxonMobil is concerned that BHP Billiton's statement fails to reflect the nature of the competitive forces (being the synchronous timing of volume commitments) and the deficiencies in the regulatory framework (particularly the inflexibility, excess time and cost) that have an impact on large new gas projects such as the PNG project. (sub. DR78, p. 3)

The ESC commissioned McLennan Magasanik Associates to study the deferral of Victorian distribution network extensions. The study concluded that very few of the potential projects were commercially viable:

> 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, p. i)

Service providers generally disagreed with the view that the Gas Access Regime has encouraged new investment:

> APIA believes that this is very far from the truth and that the pipeline construction that has occurred over this period has actually been *in spite of* the [Gas] Code … Pipeline developments involve long lead times, suggesting many of the projects were committed to prior to the pipeline companies realising how the Code would actually be implemented. (APIA, sub. 44, p. 34)

> Incumbent energy users and regulatory authorities with significant roles in applying the Gas Access Regime … [have attributed] a range of new investment in gas infrastructure assets during the operation of the Gas Access Regime to the regime itself.
>
> This is an unsustainable attribution, not supported by the evidence, which should not be the basis of any policy recommendations from the Productivity Commission. (AGA, sub. 13, p. 62)

Some participants suggested that the long lead time between a decision to build a pipeline and construction commencement means that arrangements for most of the investment that has taken place commenced before the Gas Access Regime was implemented. As noted by Duke Energy International:

> The Gas Code was just coming into play at that time [the time Duke Energy International acquired the right to build the Eastern Gas Pipeline] and so we were

> already well down the path of investing into that Eastern Gas Pipeline, so the point there being it's probably not a fair assertion to say that the Code has encouraged investment. The Code was just coming into place; the investment decision had already been made. (trans., p. 378)

The AGA commented that evidence such as aggregate listings of expansions in the physical length of transmission pipelines, aggregated capital expenditure, and long-term patterns of gas consumption do not:

> … provide a basis upon which to conclude either that the Gas Access Regime has not impacted on investment, or that significant amendments should not be made to the regime to reduce the potentially negative impact of the regime on future investment. (sub. 68, p. 6)

Specifically, the AGA (sub. 68) disputed BHP Billiton's claim that capital expenditure in distribution networks has increased by up to 15 per cent per annum in the 1990s. It noted significant structural changes that have occurred and cautioned against comparing gas industry data over this period. The AGA further noted that BHP Billiton used a base year for its calculations in which there was abnormally low investment and that some capital expenditure was underreported in the early 1990s. The AGA (sub. 68) submitted revised figures that show capital expenditure in gas distribution networks declined by 3 per cent per annum over the period 1990–2002.

The Commission has summarised the data from BHP Billiton and the AGA (figure 4.3). There is an upward trend in the BHP Billiton data and there is a downward trend in the data adjusted by the AGA. Overall, it is difficult to draw strong conclusions from the data. Further, there could be many factors explaining the variability in the data (other than the Gas Access Regime).

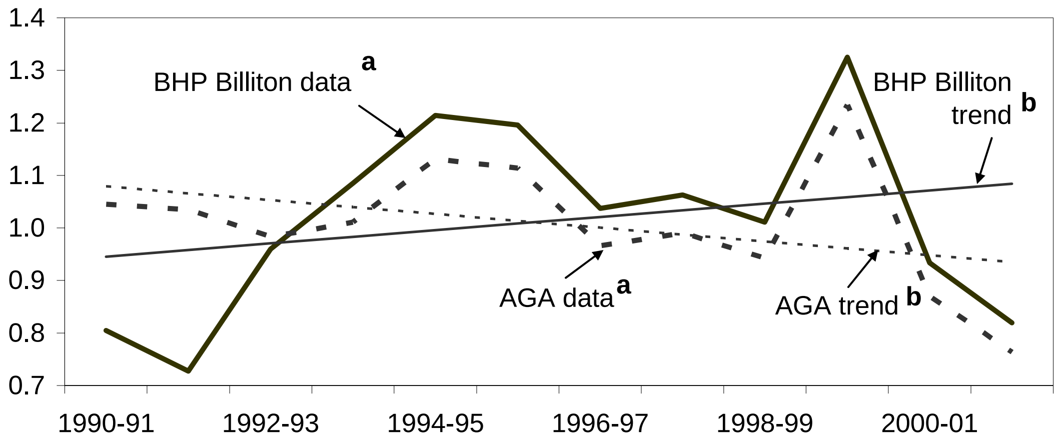
'Safe' investments and suboptimal pipelines

As noted in the conceptual framework outlined above, cost-based price regulation might distort investment decisions in favour of lower risk projects. This might be evident in a greater reliance than otherwise on:

- only building capacity that is essentially fully contracted prior to construction
- incremental expansions.

The AGA (sub. 68, p. 7) noted there is potential under the Gas Access Regime for 'investment to proceed, but to be configured in a socially suboptimal way'.

Figure 4.3 **Capital expenditure on distribution networks**



[a] The Commission created an index of each data series using the geometric mean of the series as the base.
[b] Regression analysis indicates that the slope of each trend line is not significantly different from zero.

Source: PC estimates based on data provided by BHP Billiton, sub. 26, p. 30; AGA, sub. 68, p. 8.

Similarly, Enertrade claimed:

> … investors' focus will be distorted increasingly from building and or operating pipelines in ways that enable efficient market growth to building and or operating pipelines in ways designed to avoid regulation. Enertrade does not claim that investment will stop. The real issue is that the regime distorts industry decision making and diminishes the benefits Australia obtains from its gas resources. (sub. 14, p. 2)

Envestra observed:

> Projects undertaken by regulated businesses since the introduction of the regime in 1997 have been very low risk. Higher risk projects have proceeded on the basis that they would not be regulated ... (sub. 22, p. 37)

It might be the case that investors have proceeded only with projects they expect to deliver the relatively low returns allowed by the regulator (and by implication pose relatively little risk, since there is a risk-return tradeoff). A distortion thus arises because some risky projects, which might be desirable for the Australian economy, do not proceed as early as they might have otherwise.

Various inquiry participants suggested the Gas Access Regime has increased the incentive to size pipelines so that capacity is essentially fully contracted prior to construction:

> In addition to projects that may not proceed, the threat of regulation may cause the service provider to 'undersize' the pipeline so there is only sufficient capacity to meet obligations for the foundation customers that underwrote the development of the

> pipeline … Such an outcome is inefficient, and not conducive to the development of Australia's emerging gas market. (Duke Energy International, sub. 21, p. 11)
>
> Potential consequences [of increases in regulatory uncertainty] include underinvestment in pipeline infrastructure, through the construction of pipelines with only sufficient capacity to meet the needs of foundation customers. (Northern Territory Treasury, sub. 41, p. 2)
>
> … in the current regulatory environment we would only consider further investment in regulated pipeline infrastructure if the risk of regulation could be effectively removed by ensuring that all capacity on the pipeline was covered by long-term contracts from the outset. Building pipelines for today's demand only with no spare capacity for the future is an inefficient outcome for Australia and a direct result of overzealous regulation. Sadly, however, the only alternative at present is to attach a premium for regulatory risk which has already made many such projects uncompetitive. (Deutsche Asset Management, sub. 66, p. 3)
>
> … when investments are undertaken, there is an increasing tendency for them to be sized for short-term demand so that the scale economies that could be secured to minimise the long run average cost of the provision of gas transmission services are foregone. (APIA, sub. DR100, p. 18)

The South East Australia Gas (SEA Gas) Pipeline — joining Port Campbell and Adelaide — was nominated as an example of a pipeline that was built so that capacity was essentially fully contracted before construction:

> A good example [of a pipeline built without spare capacity to minimise third party access risk] is the SEA Gas Pipeline. It is our understanding that this pipeline has been constructed without spare capacity and the question should be asked, is this the most efficient outcome for the industry as a whole? It is ExxonMobil's experience that there are often significant economies of scale that can be achieved at the time of construction, as additional pipe diameter is cheaper than adding compression or looping the pipeline at a later date. If there is no incentive, or even worse a disincentive, for pipeline developers to provide spare capacity, ExxonMobil believes that the industry is missing an opportunity for efficient longer term growth and additional competition. (ExxonMobil, sub. 8, pp. 4–5)
>
> As the implications of regulatory decisions have emerged, a rational response has been a tendency to size new pipelines based only on the requirements of foundation contracts (as appears to be the case with the SEA Gas Pipeline). From a pipeline owners' perspective, this reduces the potential for coverage under the [Gas] Code; and even if a coverage application was successful, the absence of spare capacity would be expected to reduce regulatory uncertainty. The adverse consequence of minimum pipeline sizing is that opportunities to induce investment in pipelines sized for future market growth have inevitably been lost. (Australian Pipeline Trust, sub. 55, pp. 6–7)
>
> … the Gas Code, besides the obvious problems for investors associated with inadequate rates of return, also contains provisions which engender a second order investment risk which induces 'capacity truncation' in any pipeline which might proceed, despite the Gas Code. Goldfields Gas Transmission understands that this effect is exemplified in

> the South Eastern Australia Gas (SEA Gas) Pipeline, which has been built without any specific provision for expansion of capacity, as one might have normally expected of a pipeline facing the commercial prospects which might be anticipated in the circumstances of that particular investment. (Goldfields Gas Transmission, sub. 18, p. 11)
>
> Unfortunately, it appears that the SEA Gas Pipeline is the first example of investors building pipelines, in an inefficient manner, purely to avoid the current approach to access regulation. An inevitable result of this outcome is that eventually, more expensive augmentation of the pipeline will occur, and ultimately, at the expense of customers. (Duke Energy International, sub. 21, p. 8)

On the other hand, the ACCC claimed there is little evidence of pipelines being built too small, and presented a counter-argument for the SEA Gas Pipeline:

> One pipeline that is often used as an example [of a pipeline being built too small] is the SEA Gas Pipeline that is currently under construction from Victoria to Adelaide. I find that a surprising claim … the SEA Gas Pipeline has the potential to more than double the gas being made available to Adelaide … The SEA Gas Pipeline is significantly bigger than the new pipeline that's being built running from Longford, an important gas source, to Sydney, an important gas market. It seems to me, when you consider all those facts, it is extremely difficult to argue that the SEA Gas Pipeline is underbuilt. (trans., pp. 328–9)

BHP Billiton made a similar point:

> The assertion by some that the [Gas Access] Regime means that pipelines are only being sized to meet the capacity reservations of foundation shippers is not supported by the evidence … The SEA Gas Pipeline has a fully compressed capacity of 125 PJ pa [per annum] effectively doubling delivery capacity into the South Australian market. It can be expected that the market will take a long time to double in size. (sub. 62, p. 2)

There is some debate about whether sizing pipelines to meet only contracted demand is a form of distortionary behaviour. It might make good business sense to build a smaller pipeline, given market forecasts. In this regard, Mr Michael Cavell (Chief Executive Officer of Enertrade) mentioned his experience when employed by Duke Energy International:

> What we were seeking to do on the Eastern Gas Pipeline was find an optimal outcome. We built an 18 inch pipeline but it could have been 20, it could have been 24, it could have been 16. The diameter that would have fit the marketplace at that time, which was one customer, was 14 inch. We could have built a 14 inch pipeline from Longford to the Port Kembla Steelworks and satisfied BHP and Sydney would have received nothing, because there were no customers there at the outset. The decision to pick 18 inch was based upon a forecast of growth that suggested that the need for the first expansion would be approximately 10 years in the future. Therefore that was an acceptable period of operation before the pipeline became constrained and would give us the opportunity to grow the marketplace, if you will, and deliver returns to our shareholders without the need for additional capital. So it was a balanced judgment

made that, at that point in time the 18 inch was optimal for our forecast of the market. I mean, we could have been wrong; it could have taken 20 years for the market to grow. That's the risk we were prepared to take; that we could do something about it. We could forecast that market and we would build, if you will, the optimal initial design. (trans., pp. 280–1)

Similarly, the ACCC noted:

> In terms of addressing this question of undersizing and [the claim that] it is more efficient to build larger pipelines, I do not think that is right. I do not think it is right for a number of reasons, the first being that oversizing a pipeline substantially beyond demand initially has a very substantial cost associated with it too which needs to be taken into account. That is the cost of bearing the higher construction cost — the capital cost over time — when a large part of that pipeline is empty. It also has a lot of risk associated with projecting demand for that pipeline. (trans., p. 330)

Nevertheless, Sleeman Consulting observed that regulation could be a factor that leads to pipelines being sized to meet known demand:

> Risk-return tradeoffs will likely mean that preinvestment in capacity to service future market requirements is unlikely unless the prospects for securing load growth are high enough to warrant a dilution of base case returns.
>
> The risk-return tradeoff will be influenced by:
>
> - Competitive pressures in an interconnected market place, which mean that pipeline service providers can have little certainty regarding the share of market growth that they may secure; and
> - To a lesser extent, by regulatory concerns, particularly the impact that coverage of the pipeline might have upon the ability to derive returns of the level envisaged at the time of a commitment to invest. (ACCC, sub. DR101, attachment E, p. 14)

Low risk investments and suboptimal pipelines might be costly from society's point of view. The effects of these distortions in investment might be cumulative, and the adverse effects of only low risk pipeline investment might take up to a decade to have an impact.

4.6 Impact on pipeline investment — the Commission's assessment

Many inquiry participants commented on the impact of the Gas Access Regime on pipeline investment. Users and regulators presented information about pipeline investment taking place, but service providers argued that any investment has been in spite of the Gas Access Regime. Service providers further argued that the nature and timing of pipeline investment has been distorted. Lower risk or suboptimal pipeline developments might proceed, but not riskier pipelines or pipelines that cater for future growth in the demand for gas pipeline services. Although distorted investment might not be as damaging as no investment, it is inefficient and might hinder the development of the Australian gas market.

It is difficult to draw conclusions from the information provided by inquiry participants because the 'no regulation' scenario is unobservable. Projects that did not proceed might not have been viable in any event. On the other hand, observing actual investment does not prove that investment has not been distorted. For example, growing gas demand probably would have led to some investment taking place in any event.

The Commission, therefore, considers that an assessment of whether the Gas Access Regime has improved the efficiency of investment must include an examination of the likelihood that:

- cost-based price regulation will be applied to pipelines with little or no market power
- there will be regulatory error in setting prices, regulatory risk or asymmetric truncation.

Chapter 2 found that gas pipelines do have natural monopoly characteristics, but their market power might in some cases be constrained by various factors. Thus, for some pipelines the potential improvement in investment efficiency from cost-based price regulation might be small and difficult to realise in practice. The Commission's assessment, detailed in chapter 6, is that this is a real possibility because the Gas Access Regime's coverage test sets too low a threshold for cost-based price regulation.

The Commission also considers there is a potential for regulated prices to incorporate regulatory errors due to the complex issues involved and the need to make subjective judgments about risk. There is also reason to consider that if regulatory errors do occur under the Gas Access Regime, then they will tend to reduce expected profits for riskier projects below what is needed to encourage efficiency. For example, the expected rate of return allowed by regulators has been based on the precedents set for existing, possibly lower risk, pipelines:

> In Australia, few infrastructure assets are traded in the market. The response of early regulatory decisions … was to take some average of traded assets from overseas (usually the US and/or UK) and then adapt this to reflect Australian market conditions. Later Australian regulatory decisions have often based decisions on beta on the perceived riskiness of the particular pipeline being regulated compared to those for which betas have been determined in the past in Australia. Tables comparing betas allowed in previous regulatory decisions in Australia are a common feature of Draft and Final Decisions by regulators. We do not believe this to be an ideal approach, as

> the comparisons made are often subjective, but recognise the limited availability of alternatives. (IRIC 2003, pp. 18–19)

In addition, recent appeal decisions suggest that regulators err in favour of lower returns. For example, the Australian Competition Tribunal found that the ACCC had made errors with respect to regulatory parameters used for GasNet's access arrangement, including the bond rate used to calculate the *ex ante* regulatory rate of return, that disadvantaged the service provider (*Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6).

The Commission is also of the view that regulatory risk is high under the Gas Access Regime because of:

- *coverage risk* — investors cannot obtain a binding commitment from regulators as to whether a proposed pipeline would be subject to the Gas Access Regime
- *parameter risk* — investors cannot always be certain about what parameters (such as for the cost of capital) a regulator will consider appropriate and whether the regulator will change its view over time
- *asset stranding/redundant capital* — investors might be prevented from recovering their capital costs due to the redundant capital provisions of the Gas Code
- *changes in foundation customer incentives* — foundation customers have a strong incentive under the regime to include 'most favoured nation' clauses in their contracts, which can transfer risk to service providers.

In its draft greenfields guideline, the ACCC (2002a) claimed it has taken steps to address the investment chilling effects of regulatory risk. In addition, the ACCC noted:

> … we recognise that regulatory risk is an issue. That's an issue particularly for new pipelines, and part of our job is to ensure that that regulatory risk is minimised. That underlines the importance of the [draft] greenfields guideline ... (trans., p. 330)

The ACCC also claimed there is scope under the Gas Code to address investor perceptions that profits can be asymmetrically truncated:

> The ACCC recognises that if there is a perception that regulators may truncate high return scenarios then socially desirable investment may be delayed or deterred. To address this concern the ACCC has indicated in the greenfields guideline that it is prepared to bind its future discretion by entering into an extended upfront regulatory agreement with pipeline proponents … For pipelines that face an uncertain demand situation, a benefit sharing mechanism can be incorporated in the access regime which would share profits (losses) between users and the pipeline developer in high (low) return situations. This would provide certainty about the treatment of high (low) returns in the future … [and] mechanisms such as adjustments to the depreciation schedule or

> the capitalisation of losses could be incorporated into the access agreement to offset the potential for losses in the early years of a pipeline. (sub. 48, p. xiii)

The extent to which the remedies identified by the ACCC overcome potential problems with the Gas Access Regime is considered in chapter 9. As discussed in that chapter, the Commission has concerns about the scope to address regulatory risk and asymmetric truncation under the existing regime.

Evidence of asymmetric truncation is not clear cut, due to the limited number of access arrangement reviews to date. In addition, it is difficult to establish whether benefit sharing rules or recontracting at an access arrangement review transfer benefits to users at a faster rate than would be anticipated by a competitive service provider. Nevertheless, the Commission considers that competitive investors will anticipate asymmetric truncation under the Gas Access Regime, particularly for riskier projects, because of the:

- wide profit distribution for risky projects — it is difficult for regulators to distinguish between competitive pipelines that experience better than expected outcomes and pipelines that are exerting market power
- incentives faced by regulators — regulators can face pressures to truncate high profits because of their consumer advocacy role, asymmetry in observing regulatory errors, regulator risk aversion, and mistrust of the information provided by service providers.

In summary, the Commission considers the Gas Access Regime is likely to distort pipeline investment in favour of lower risk projects, including through the deferral of riskier projects. This is due to the combination of the current coverage test and the potential for regulatory error, regulatory risk and asymmetric truncation.

The adverse impact of the regime on pipeline investment is likely to have negative impacts on upstream and downstream industries. As a practical example, Alcoa commented on Epic Energy's inability to expand the Dampier–Bunbury pipeline to meet the expectations of major users:

> Epic Energy has … found itself limited in its capacity to continue as owner, operator and to expand the [Dampier–Bunbury pipeline] in order to meet expectations of major users. The situation that has developed has produced uncertainty for major users with flow on implications for economic development in Western Australia.
>
> … Alcoa is looking to maintain the confidence to invest in plant and equipment for large-scale and long-term production. Alcoa's expansion in Western Australia rests on its ability to produce alumina at an internationally competitive price. The availability of long term, secure, internationally competitive gas supplies is an important element in any feasibility studies and planning activities. (sub. 65, p. 6)

FINDING 4.3

The Gas Access Regime is likely to be distorting investment in favour of less risky projects, including altering the nature and timing of pipeline investments. Pipeline construction might be delayed, for example, and there might be greater emphasis on building capacity that is essentially fully contracted prior to construction. Such alterations can inhibit the emergence of competition in upstream and downstream markets and generate inefficiencies.

Impact on innovation

There is also a concern that the Gas Access Regime discourages risky investments that involve technological change and service offering innovation. That is, 'dynamic efficiency' is lower than otherwise. Service providers will only have an incentive to invest in technological improvements and other innovations if they expect to receive a return commensurate with what they perceive to be the associated risks.

Technology used in pipeline transmission and distribution is continually developing. The transmission industry has been assisted by improvements in pipeline steel that can improve the safety and longevity of pipelines. Pipeline walls might become thinner, reducing overall material requirements and leading to lower costs. Other improvements might be made in the compressor technology and the machinery that can dig and lay pipelines.

Service offering innovations are generally improvements made at the retailing stage — for example, gains made in the discovery and tailoring of services to meet customer preferences. These gains come from the development of new services and/or improvements in existing services.

The Gas Access Regime might discourage investments in innovation due to:

- the truncation of additional returns that service providers make through dynamic efficiency gains
- uncertainty about whether regulators will allow investment, such as research and development or market research, to be classed as prudent investment and thus recovered through reference tariffs.

On the potentially chilling effect on innovation, technology and quality, Allgas Energy noted:

> The focus has typically been on maintaining existing service levels at low 'competitive' prices, in order to curb or eliminate inefficient monopoly rents. Such a heavy-handed top–down approach is intrusive and potentially distorting … with its demonstrated

> chilling effect on innovation in technology, quality and service offerings. (sub. 25, p. 82)

Enertrade noted the effect of cost-based price regulation on business activities:

> Managers have no incentive to develop their market; rather they are forced to focus on managing their business according to the exactions of the regulator. This rules out significant improvements in dynamic efficiency. (sub. 14, p. 8)

ENERGEX noted in its submission to the Commission's review of the national access regime:

> … there will be no dynamic efficiency or technical progress in the sorts of models currently employed in Australia. The Schumpeterian 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*. (ENERGEX 2001, p. 81)

APIA stated:

> The costs [from the application of regulation] include, for example, the foregone benefits that are lost when a regulated business focuses on managing the regulator rather than on improving their business through innovation aimed at better serving customer needs. (sub. 44, p. 37)

FINDING 4.4

Information provided by interested parties supports the view that the Gas Access Regime might have a discouraging effect on innovation and improvements in service offerings.

4.7 Price regulation when there is not substantial market power

Transmission pipelines and distribution networks exhibit natural monopoly characteristics (chapter 2), but not all have substantial market power. Competition among transmission pipelines has emerged, and other forces also exert competitive pressure on transmission pipelines (such as competition from other fuels, the bargaining power of users and the elasticity of derived demand for the pipeline services). Similarly, other forces exert competitive pressure on distribution networks (in particular, competition between natural gas and electricity in the residential and commercial sectors).

There are circumstances, therefore, where the markets in which transmission pipelines and distribution networks operate are imperfectly competitive — in other words, the market power of service providers is constrained. The existing Gas Access Regime is a form of cost-based price regulation where the services provided and prices charged to third party access seekers default to those approved by regulators (chapters 3 and 7).

Generally, economics does not provide clear guidance about how to regulate prices in imperfectly competitive markets. In such markets, it might be preferable to rely on market outcomes than to apply price regulation (PC 2001d).

Demsetz, in exploring the guidance that economics can offer antitrust policy, noted:

> For antitrust problems … the primary issue is the assessment of the competitiveness of industrial behaviour, with a view toward increasing competition where it is found inadequate. It is a problem to which relatively little theoretical attention has been given. Determining the degree of competitiveness is a very different problem from the application of either the competitive or monopoly model to a particular situation. (Demsetz 1989, p. 196)

Analysing appropriate policy interventions for imperfectly competitive markets is much more complex than analysing that of the idealised polar cases of competitive or natural monopoly markets. It can be particularly difficult to determine (1) which businesses are candidates for regulation and (2) how and at what level they should be regulated, if at all. Joskow and Rose noted:

> When competing firms operate in a regulated market, the nature of price regulation itself typically changes, and the variety of possible regulatory effects expands … While many of the variables that can be affected by regulation are the same as those described for monopoly markets, the nature of the regulatory effects may differ considerably from those that emerge when a single legal monopoly firm serves a particular market. (Joskow and Rose 1989, p. 1455)

The Industry Commission recognised the difficulties in regulating prices in imperfectly competitive markets in the context of prices surveillance. However, these difficulties apply more generally:

> … the efficient regulation of the prices of duopolies and oligopolies is likely to require more information, and deftness in changing circumstances, than is available to any regulatory agency. … The limitations of prices surveillance are so marked that it is doubtful whether it can make a constructive contribution to consumer welfare in duopolistic and oligopolistic markets. (IC 1994, p. 79)

Given the difficulties of regulating imperfectly competitive markets, attempting to fine tune them is unlikely to lead to improved outcomes, particularly where cost and demand conditions change over time:

Although regulation can be welfare improving in an imperfectly competitive market, it is perhaps unwise to support a regulatory policy that attempts to finetune such markets. One major obstacle to implementing such a policy is that it is often extremely difficult to determine which markets are candidates for regulation as well as what level price should be set. This latter problem is especially troublesome when cost and demand conditions change substantially over time. That a market has only a few firms is not a sufficient condition for regulation to be welfare-improving, inasmuch as competition may nevertheless be strong because firms are innately competitive or because potential competition forces them to be so. Regulation in such markets is likely to reduce welfare. A policy of trying to finetune imperfectly competitive markets through price regulation is a perilous task that has been shown historically to be self defeating. A general policy of relying on unfettered competition seems advisable in markets that are not natural monopolies. (Viscusi, Vernon and Harrington 2000, p. 503)

US experience in gasoline, airlines and surface freight transport industries illustrates the riskiness of regulating imperfectly competitive markets (Viscusi, Vernon and Harrington 2000). In the context of imperfect markets in electricity transmission, Hogan noted:

In balancing imperfect markets and imperfect regulation, lean towards markets. The goal should be to mitigate egregious market power that has a substantial and sustained effect. Trying to use regulation to force the theoretical limit of perfect competition probably does more harm than good because regulated solutions are also imperfect. (Hogan 2004, p. 1)

In Australia, the market conditions facing the gas transmission and distribution sectors have changed significantly from the conditions prevailing when the Gas Access Regime was developed. Gas basins and pipelines are beginning to compete to service specific markets, such as Adelaide and Sydney. Further, the natural gas transmission system in eastern Australia is likely to become increasingly interconnected. This trend has the potential to increase the volatility of prices, volumes, and direction of gas flows for individual pipelines, as producers, pipelines and users respond to the market opportunities of such an increasingly competitive market (chapter 2).

In the context of a changing gas market in Australia, Professor Stephen Littlechild noted:

… the purpose and nature of network regulation needs to be kept under review. There may be merit in tough regulation of monopolies, designed to minimise price consistent with rewarding efficiency. However, in a potentially competitive market the advantage is in relaxing and ultimately removing the regulation of prices, so as not to discourage new entry and investment, and so as to encourage the development of competition to provide network services.

Gas networks seem to be a case in point. Customers often have a choice whether or not to use gas, gas retailers have a choice of pipelines, there is competition to build new

> pipelines, and the building and extending of gas distribution networks has to compete against the provision of other fuels. In such circumstances the need for regulation is substantially reduced. At the same time, the potential costs of regulation — in terms of 'getting it wrong' and discouraging investment — can be quite significant. (sub. 24, p. 3)

Based on the academic literature, inquiry participants' comments and historical lessons, and earlier evidence on the costs of the existing regime, the Commission considers there is a case for limiting the application of access arrangements with reference tariffs.

FINDING 4.5

Generally, cost-based price regulation should be considered only if service providers have substantial market power. Where market power is not strong, such as where there is emerging competition, in the long run the costs of regulated prices are likely to outweigh the cost of the market failure that such regulation attempts to correct.

4.8 Direct costs

Direct costs arise from the operation of the Gas Access Regime, essentially in the form of compliance costs for the sector and administration costs for regulators. There might be differences, however, between which parties initially bear these costs and which ultimately 'pay'. Users, for example, contribute to the extent that service providers can include some of their costs of developing access arrangements in their reference tariffs. Also, in some cases, regulators recover some of their costs from service providers and users (through fees and service and standing charges which might be passed through to users as part of reference tariffs). It can be complex to work out who ultimately bears the costs. Nevertheless, even though these costs can be borne by users, resources are expended and therefore cannot be used elsewhere in the economy, so these costs are a loss to the economy as a whole.

Some costs incurred to date have been transitional costs, as market participants (including regulators) come to understand the requirements of the Gas Access Regime. As market participants become more experienced, the costs could be lower. The ACCC noted:

> … many of the adjustment and implementation costs of establishing [Gas] Code procedures have been borne … The ongoing costs of the Code should continue to decline over time. The first round of access arrangements was always going to be more contentious and time consuming than subsequent rounds. (sub. 48, p. vii)

In contrast, APIA considered it unlikely that subsequent reviews would proceed more smoothly than the first round:

> … as the only significant issue that will not be contentious in subsequent reviews is the initial capital base which is not subject to review. This is because there remains a large number of critical issues that are, and are likely to continue to be, highly contentious and, in turn, may well lead to litigation in future reviews. These issues include the form and magnitude of asset depreciation, operating efficiency targets (including but not limited to key performance indicators), demand forecasts and the cost of capital. (sub. 74, pp. 26–7)

Service providers' compliance costs

Services providers' compliance costs are important, but measuring these costs can be difficult. Banks noted:

> Getting a good grasp of the overall magnitude of compliance burdens on business (let alone consumers) is difficult — being plagued by methodological problems and the absence of quality data. Nevertheless, the picture emerging from a range of studies suggests that the costs are large. (Banks 2003, p. 5)

In terms of the Gas Access Regime, the direct costs for businesses are significant. To comply with the regime, covered pipeline service providers must prepare access arrangements, respond to information requirements of the regulator, and prepare submissions to inquiries. The direct costs of these activities include staff time and resource and consultant costs.

Factors influencing compliance costs include:

- the frequency and duration of public inquiries (with four inquiry rounds required for an uncovered pipeline to become a covered pipeline with an approved access arrangement — before both the draft and final decision on coverage, and before the draft and final decisions on the access arrangement)
- the frequency of access arrangement reviews (with access arrangements required to have a specified review date, which is typically after five years)
- the delays by Ministers and regulators in assessing and reaching decisions (with evidence of lengthy inquiry processes and delays in decision making)
- the complexity of the compliance requirements and methods
- the level of detail and scope of information sought by regulators (with evidence that these information requirements are onerous — discussed in chapter 7)
- the extent of required modifications to accounting systems (to meet information provision and ring fencing requirements).

Some costs to service providers are payments to regulators:

- applicants for decisions face direct costs in having to pay to submit applications. Applicants must pay the NCC $7500 per application (which is not a significant amount compared with other costs)
- in some jurisdictions, service providers must contribute to meeting the regulator's costs, including legal and consultancy fees. Envestra claimed, for example:

> Regulators' costs are typically recovered through licence fees levied on the regulated business and are substantial. In 2002-03, Envestra paid annual licence fees of $1.1m and $1.2m for our South Australian and Victorian networks respectively. In addition there are costs to other parties of participating in access arrangement reviews (for example, retailers, end users). (sub. 22, p. 10)

To the extent that the Gas Access Regime's estimated total costs account for regulators' costs, the inclusion of these payments to regulators would result in double counting from a communitywide perspective.

Some inquiry participants estimated the financial costs of meeting the requirements of the Gas Access Regime. Australian Pipeline Trust noted:

> … [its] cost of participating in [Gas] Code processes such as access arrangements and revocation applications is estimated to be $4.5 million over the last three years. This excludes significant expenditure on processes commenced prior to the formation of [the Australian Pipeline Trust]. (sub. 55, p. 12)

APIA noted that the transaction costs of the current regulatory framework are extremely high:

> For example, APIA's members estimate that they have expended the sum of $14 million in interfacing with the first round of regulatory reviews (with an additional $13 million being expended on litigation associated with these reviews). (sub. 44, p. 79)

Envestra considered that the costs of preparing an access arrangement and obtaining regulator approval are high:

> Envestra estimates that its own cost of preparing an access arrangement varies from $250 000 for a small network (for example, Albury Gas Company) to $2 million for a larger network (for example, Victoria). (sub. 22, p. 9)

Epic Energy noted that its costs from the Dampier–Bunbury pipeline access arrangement process included the cost of preparing over 100 formal submissions to the regulator, $2.5 million in hiring consultants, $2.5 million in payments of the regulator's costs (excluding the $800 000 that the regulator incurred in participating in a legal challenge of the draft decision). It could not quantify the time spent by management on regulatory matters, but noted 'the consequences of a lost development opportunity would be significant' (sub. 37, p. 64). Some of these costs might have arisen from the interaction of the structural reform program, the privatisation process and the Gas Access Regime.

APIA noted:

> In the case of CMS' Parmelia Pipeline, a pipeline that demonstrated through the revocation process that regulation was unwarranted, total regulatory costs amounted to more than $600 000 up to the point of revocation. This is a particularly perverse outcome as not only should the Parmelia Pipeline never have been covered, but a number of other Western Australian pipelines were never covered. (sub. 44, p. 27)

NT Gas noted that the access arrangement process for the Amadeus Basin–Darwin pipeline (which was covered by its inclusion in schedule A of the Gas Code):

> … cost in the order of half a million dollars, despite the fact that no capacity was available nor was it likely to be sought in the foreseeable future. It is arguable that the [pipeline] should not be covered as it is unlikely to meet the [Gas] Code coverage criteria. However, NT Gas formed the view, once well into the access arrangement process, that compliance with the Code from that point was likely to be less expensive than embarking on the revocation process. (sub. 64, p. 2)

Further, NT Gas noted that, in 2003, faced with the choice of developing an access arrangement or seeking revocation for the City Gate–Berrimah pipeline (which was also covered by its inclusion in schedule A), it:

> … submitted an application for revocation (which was successful). However, the cost of the relatively simple application has still had a very significant impact on the financial operation of the [pipeline]. Thus, the [Gas] Code has imposed a series of unnecessary costs on the [pipeline] (amounting to 23 per cent of its annual revenue in the year revocation was sought) arising out of the original policy decision to deem it covered from the commencement of the Code. (NT Gas, sub. 64, p. 2)

Some inquiry participants considered that some compliance costs are broadly fixed, so are more significant for smaller pipelines. Envestra noted:

> A large portion of the compliance costs are fixed irrespective of the size of the network. Access arrangement review costs are up to $2 million for networks owned by Envestra. (sub. 22, p. 31)

The costs of the Gas Access Regime's prescription of access arrangements with reference tariffs are discussed further in chapter 7. Enertrade noted:

> I've been working in this industry, as I said, for 25 years, and a good part of that time has been spent on the vagaries of cost-of-service regulation, both from the standpoint of an advocate and then ultimately from the standpoint of an executive within a company that was subjected to it. I don't think I have ever seen more counterproductive activity than I have seen in the processes that are embodied in cost-of-service regulation. It's in many ways a jobs bill.

> It creates an industry of its own. It creates an advocacy industry. It creates an advisory industry. It creates a consultant industry, and ultimately it does virtually nothing for the marketplace. It becomes a technical debate about technical issues having to do with costs and prudency of costs incurred and capital bases and references to capital markets, to capital as a pricing model, none of which has anything to do with the commercial marketplace in which these pipelines operate. (trans., p. 275)

Not all of the compliance costs might be attributed to access regulation. Without regulation, compliance costs would still arise from commercial negotiation (PC 2001c, p. 63). The ACCC noted:

> … in the absence of the current [Gas Access] Regime, industry would continue to encounter many of the costs currently incurred and may well encounter additional costs. For example, the costs incurred in developing a base set of terms and conditions with the regulator might be replaced with the costs of negotiating multiple access agreements with prospective users. (sub. 48, p. 75)

However, many of the costs highlighted above would be unlikely to occur through commercial negotiations. Envestra considered that ‘unregulated commercial negotiations would only cost a very small fraction’ of the costs that it incurred in access arrangement reviews (sub. 22, p. 31).

The Commission considers that the Gas Access Regime results in significant compliance costs to service providers through the coverage and revocation process, and through access arrangement requirements.

Government administration costs

Across the economy, governments spend significant resources on regulation. Banks (2003, p. 2) noted that ‘at the federal level, government agencies with explicit regulatory functions alone employed around 30 000 staff and spent some $4.5 billion in 2001-02’.

Governments incur administrative costs across a broad range of organisations in administering the Gas Access Regime. However, if the regime did not exist (or if an alternative regime was in place), governments would still require some resources for policy development. The ACCC noted:

> On the government side, it is likely that significant compliance costs would continue to be encountered if the current [Gas Access] Regime were replaced with an alternative. In addition to the adjustment and implementation costs that would arise in setting up the new regime, government resources would continue to be required to administer and enforce the new regime. Government resources will continue to be required in developing energy policy no matter what type of regime is in place. (sub. 48, p. 75)

Nonetheless, regulators (whose role arises from the regime) appear to use significant resources in administering the regime. The AGA reported results from a July 2003 study that measured the direct costs to government of regulatory authorities administering the Gas Access Regime. The study found:

> … the total cost of gas industry regulation (including market, access and licensing regulation on the transmission, distribution and retail sectors) on regulatory authorities is likely to fall within a range of $16.7–18.8 million per annum, with a minimum annual cost of around $5.4 million for gas access arrangements alone. (sub. 13, p. 16)

APIA concluded that ‘it is not unreasonable to suggest that the cost of regulatory bodies around Australia in gas transmission regulation is in the order of $4–5 million per annum’ (sub. 44, p. 31). The Institute of Public Affairs estimated:

> In terms of government regulators, … some 450 full time equivalents [are] involved in the economic regulation of the gas and electricity industries. In addition to these there are several hundred more involved in social regulation — safety, environmental, greenhouse and so on. (sub. 2, p. 9)

Epic Energy noted that the costs of the regulator in Western Australia have been increasing:

> In the case of the [Western Australian] regulator, the costs of his office and that of the other institutions that have been established under the Gas Access Regime have increased significantly since they were first created in 1999. This is demonstrated by [material elsewhere in Epic Energy’s submission] which outlines the costs that have been imposed by service providers of [Western Australian] covered pipelines through standing charges since the establishment of the funding regulations under the [Western Australian] Gas Access Regime. These costs are additional to the direct costs of the regulator in undertaking assessments of access arrangements under the national Gas Code (which are recovered by way of service charges). In the case of Epic Energy, these costs now total over $1 500 000. (sub. 37, p. 67)

The Western Australian Government noted that the costs of the Office of Gas Access Regulation were less than 1 cent per gigajoule of throughput of regulated pipelines between 1999-2000 and 2002-03 (sub. 70, p. 8). The National Gas Pipelines Advisory Committee, which is responsible for recommending changes to the Gas Code to Ministers, noted that its total expenditure in 2002-03 was about $400 000 (sub. 34, p. 7).

Government regulators generally did not provide the Commission with estimates of their costs of administering the regime. Based on the evidence from some inquiry participants, however, the Commission considers that these costs are not insignificant.

Users' costs

Users face costs in participating in the public consultation processes of the Gas Access Regime. They provide input to public inquiries because regulation influences the prices that both direct users and end users face. This input requires staffing and other resource costs, such as consultants' fees.

Users that make applications for coverage also incur the $7500 coverage application fee of the NCC. Given the way the Gas Access Regime was implemented, there has been only one coverage application, made by a potential user of a pipeline (AGL Sales and Marketing). In the future, potential users of pipelines are likely to make most, if not all, applications for coverage. Again, in determining the communitywide costs, payment of these fees should not be included if the NCC's total costs are included. Otherwise, there would be double counting.

While the Gas Access Regime might involve significant costs to service providers, users might consider access arrangements to be less costly than commercial negotiations. Worsley Alumina noted:

> The costs of compliance with the [Gas] Code are relatively minimal for Worsley so long as Worsley seeks a 'reference service' or near equivalent. In Worsley's experience to date this has been all that has been available. Worsley contrasts this with the expected costs of compliance with the state's rail access regime. Under this regime the access charge is negotiated by the rail owner and user between upper and lower limits set by the rail access regulator. Worsley anticipates that it will be extremely difficult to achieve a satisfactory outcome in such circumstances and that it may be necessary to rearrange the way it conducts its rail operations to fit in with the access regime. (sub. 5, p. 2)

4.9 Other costs

Other costs of the Gas Access Regime arise from inadequate timeliness, distortions in service provider and user behaviour and the pressures facing regulators (including the risk of being captured).

Timeliness

Costs arise from delays in decisions or approvals. The Gas Code allows considerable flexibility in the time taken for decision making. Some decisions have taken considerably longer than the time envisioned by the legislators.

The timeliness of access arrangement approvals is presented in table 4.2. All decisions have taken at least one year, with six arrangements taking over three years to finalise. The Moomba–Sydney access arrangement, for example, was first submitted in May 1999 and was approved in December 2003. Approval of access arrangements for transmission pipelines generally appears to take longer than for distribution networks (except in the case of South Australian distribution network).

Table 4.2 **Timeliness of access arrangement approvals**

Pipeline	*State or Territory*	*Time for approval of initial access arrangement*	*Time for review*
Transmission pipelines/systems			
Victorian transmission system	Vic	1 year 1 month	10 months[a]
Moomba–Adelaide	SA	3 years 3 months	na
Moomba–Sydney system	SA/NSW	4 years 7 months	na
Ballera–Mount Isa (Carpentaria Gas Pipeline)	Qld	1 year 10 months	na
Ballera–Wallumbilla	Qld	1 year 10 months	na
Wallumbilla (Roma)–Brisbane	Qld	1 year 10 months	na
Wallumbilla–Rockhampton (Queensland Gas Pipeline)	Qld	1 year 3 months	na
Marsden–Dubbo (Central West Pipeline)	NSW	1 year 9 months	na
Amadeus Basin–Darwin	NT	3 years 9 months	na
Dampier–Bunbury	WA	4 years	na
Tubridgi	WA	2 years	na
Parmelia Pipeline[b]	WA	1 year 7 months	na
Goldfields Gas Pipeline	WA	4 years 6 months+[c]	na
Distribution networks			
Multinet Gas, Westar Energy and Envestra systems	Vic	1 year 1 month	8 months
Envestra SA distribution	SA	4 years 2 months	na
Albury Gas Company	NSW	1 year 7 months	8 months
Wagga Wagga (Great Southern Energy)	NSW	1 year 6 months	3 months+[d]
AGL NSW distribution[e]	NSW	10 months	1 year 8 months[f]
Canberra	ACT	2 years	6 months+[d]
Queensland[g]	Qld	1 year 2 months	na
Alinta Gas distribution	WA	1 year 1 month	2 months+[d]

[a] Final approval in January 2003 was subsequently appealed. The appeal decision in December 2003 modified the access arrangement. [b] Coverage was subsequently revoked. [c] Access arrangement not yet finalised. [d] Review of access arrangement not yet finalised. [e] Includes AGL Central West, Wilton–Newcastle (transmission pipeline), Wilton–Wollongong (transmission pipeline) and other pipelines. [f] The second review of the AGL New South Wales distribution network is currently underway. [g] Includes the Envestra system and Allgas Energy networks. **na** Not applicable.

Source: Appendix C.

Regulators expect the review of each access arrangement to take less time than that needed for the initial approval. The ACCC noted:

> In terms of improving the regulatory approach within the [Gas] Code at the moment, because we have just about finished the first round of access arrangements for

> pipelines, there have been a lot of things done and achieved that don't need to be replicated. The clearest example is inserting the initial capital base for all pipelines. That doesn't need to be done again. As well as that, as we get more experienced with the Gas Code and as we have a set of prices for services based on efficient costs, the scope for the lightening of the regulatory load in terms of regulatory processes also increases. (trans., p. 324)

The NCC also noted:

> … while the second round of access arrangements will have their own particular issues, there should be a greater understanding of the requirements of the [Gas] Code and the processes should be less complex, more timely and less onerous. (sub. 57, pp. 4–5)

Reviews of access arrangements appear to be shorter than the initial approvals. For those pipelines with completed reviews, the reviews took around two-thirds of the time taken for the initial approval.

Many inquiry participants commented on the impact of a lack of timely decision making on business activities:

> The deficiency in the access arrangement process is clearly demonstrated when one considers the regulatory environment in which WMC Resources operates … the Goldfields Gas Pipeline, which is the main pipeline utilised by WMC Resources, operates without an approved access arrangement in place despite the proposed access arrangement being submitted to the regulator almost four years ago. The commercial uncertainty that this sort of delay causes, and the considerable expenditure of time and resources on the regulatory process are issues of real concern to WMC Resources. (WMC Resources, sub. 43, pp. 10–11)
>
> Origin [Energy] would note that few if any access arrangements have been developed or revised in a timely manner, in most cases the development (or review) process taking more than nine months. Such delays can multiply uncertainty into upstream and downstream markets; which clearly constitutes a cost of the [Gas] Code and the Gas Access Regime. (Origin Energy, sub. 52, p. 6)
>
> The inordinate time required to achieve the regulator's final decision on the Epic access arrangement is likely largely a consequence of the [Dampier–Bunbury pipeline] sale process. The [Gas] Code has contributed to the delay in that it allows wide discretion to the regulator in reconciling objectives and weighing considerations. The length of time required for this decision has had an impact on Worsley's planning of possible future expansions. (Worsley Alumina, sub. 5, p. 2)
>
> It is now almost five years since the Gas Regime and the Gas Code was introduced in Western Australia, and more than three and a half years since [Goldfields Gas Transmission] submitted its proposed Access Arrangement. There appears to be no end in sight to the lengthy and complex process of achieving an approved access arrangement which acknowledges the position of the Goldfields Gas Transmission joint venturers under the State agreement. (Goldfields Gas Transmission, sub. 17, p. 17)

There are also costs to businesses from missed opportunities. APIA considered:

> The result of the construction and focus of the [Gas] Code has been to create unreasonable delays in finalising access arrangements, undermining the very commercial negotiations that the regime was intended to facilitate. (sub. 44, p. 29)

Delays also arise from other aspects of the Gas Code. AGL considered that the delays from the associate contract requirements placed its retailer at a competitive disadvantage:

> AGL considers that the current associate contract approval requirements in the Gas Code have resulted in a significant waste of resources, has placed its related retailer at a competitive disadvantage and, most importantly, has inconvenienced end users.
>
> An example is an associate contract relating to one customer for which the approval process began in November 2002. The contract related to one customer who will consume less than 10 TJ per annum and pay annual transportation costs of less than $50 000. [AGL Gas Networks] was prevented from meeting the needs of this customer until the approval process finished in March 2003, two months after the date for which the customer originally requested gas supply and involved a cost to AGLGN of approximately $25 000. This additional cost and delay was imposed on the market despite the fact that the end consumer was fully informed and was able to seek out competitive offers, but chose to deal with the associate retailer. (sub. 32, p. 29)

The Commission considers that the delays in access arrangement related decision making and approvals have imposed additional costs on both businesses and regulators.

FINDING 4.6

There are significant compliance and administration costs in the operation of the Gas Access Regime. Delays in decision making have added to the costs.

Distortions in service provider and user behaviour

Costs might arise from distortions in service provider and user behaviour through game playing and lobbying. Some inquiry participants considered there is potential for regulatory 'gaming' to occur under the Gas Access Regime, due to information asymmetries. Hunter Gas Users Group noted that gaming by AGL Gas Networks over information disclosure caused unreasonable delays in an access arrangement review, which in turn:

> … meant that the previous (higher-priced) access regime was extended. Lest it be suggested that regulatory gaming over information disclosures is a New South Wales phenomenon, we would suggest that it has been a common feature in access reviews in other jurisdictions, for example, the 2003 South Australian distribution pricing review took some four years! (sub. 4, p. 7)

Goldfields Gas Transmission considered that the Gas Access Regime has provided a 'significant and recurring opportunity for active and blatant gaming of the regime by existing users' which has 'distorted and added significant uncertainty' (sub. 18, pp. 12 and 13).

Enertrade also noted that users might try to game the system:

> The availability of cost-of-service regulation also encourages customers to seek regulatory intervention in the expectation of obtaining access and prices on much easier terms and conditions than commercial negotiation would produce. This means that in the presence of cost-of-service regulation, there is little value to be gained from providing or even requiring negotiation at earlier stages of the access process because customers have little incentive to bargain. (sub. 14, p. 8)

Lobbying costs are a further source of inefficiency, diverting resources away from other (more productive) uses. They might encompass industry lobbying of governments and regulators through involvement in the regulatory bargain. Often, such lobbying is motivated by the potential to gain from transfers.

A regulatory regime that gives regulatory authorities discretion in making a determination might create incentives for the interested parties to engage in lobbying, bargaining and negotiation. As noted by Yarrow:

> In the practice of regulation, supply creates its own demand: provide an authority discretionary powers and there will be no shortage of lobbyists urging the use of those powers for purposes that suit their own interests. (Yarrow 2000, p. 16)

Game playing and lobbying increase the costs to users and service providers as they try to influence the regulator or delay the outcome. These activities are motivated by the potential to influence transfers (which are larger than the efficiency gains from the change to the regulatory intervention). Consequently, users and service providers could be prepared to incur costs that are large, relative to the efficiency gains generated by regulatory intervention. Again, in assessing the communitywide costs of the regime, it is important to remember that users' and service providers' direct costs should already include the costs of gaming and lobbying.

The Western Australian Office of Gas Access Regulation noted that design of the Gas Access Regime has resulted in differing expectations:

> ... the substantial discretion required to be exercised by a regulator in balancing competing interests and resolving conflicting objectives may be beyond that consistent with the role of an umpire.
>
> The absence of prescription in the [Gas] Code and the multilayered structure of the Code in statements of objectives, requirements and principles have led to difficulties and differences of view in interpretation of the Code and in establishing a hierarchy of

> requirements and principles that must be satisfied in respect of different elements of regulation. (sub. 40, pp. 15–16)

Costs from game playing and lobbying can be exacerbated when the framework is flexible and creates an environment in which stakeholders have widely differing expectations of the possible outcomes.

A business operating in a regulatory environment also diverts resources away from conventional commercial activities towards activities required by the regulatory framework.

Pressures facing regulators

Under the existing Gas Access Regime, costs might arise from the pressures facing regulators with undertaking their statutory responsibilities. In particular, regulators might have pressures that bias decisions, incentives to overregulate, and a lack of incentives to reduce their costs.

Coverage and other decisions

In its submission to the review of part IV of the TPA, the Commission noted:

> Acting on and interpreting anticompetitive conduct is a subtle and complex task. Even experienced and informed regulators can make errors. Analysis of imperfectly competitive markets is particularly complex because the range of possible behaviours explaining observed market outcomes is large. (PC 2002c, p. 16)

One challenge is to distinguish between businesses behaving competitively and those exercising market power. There is scope for regulators to make two types of incorrect decision:

- condemning competitive conduct
- failing to act against misuse of market power (monopoly pricing).

These two are related. Attempts to avoid 'failing to act against misuse of market power' are likely to result in more cases of 'condemning competitive conduct', and vice versa (Briggs and Scheelings 1998, p. 33). Several factors influence the likelihood of an incorrect decision, including the discretion and complexity of the Gas Access Regime, market uncertainties and information asymmetries between the regulator and other parties.

Briggs and Scheelings (1998) suggested that two factors might bias regulatory decisions, such that regulators tend to condemn competitive conduct more than they fail to act against anticompetitive conduct. First, it is generally more difficult to detect a condemning of competitive conduct than a failure to act against misuse of market power. If, for example, a pipeline is covered that should not be, the prices will be regulated, but dynamic efficiency and intertemporal allocative efficiency might suffer. Such long-term outcomes on efficiency are harder to measure. Conversely, it is likely to be easier to detect the noncoverage of a pipeline with market power (for example, by observing higher prices or less access to the pipeline).

Second, if regulators are risk averse, they might succumb to the pressures from those that stand to gain from the outcomes that are tangible in the short term. That is, the regulator will err on the side of caution. Briggs and Scheelings (1998) concluded that these two factors result in a bias in favour of condemning competitive conduct rather than failing to act against anticompetitive conduct.

The incentives regulators experience in relation to coverage decisions, also arise for decisions under other areas of the Gas Access Regime, such as access arrangements and ring fencing decisions. That is, when a regulator decides to apply a lower reference tariff than that proposed by the service provider, that decision might reflect the regulator's risk aversion and the asymmetry in the outcome. Using the Briggs and Scheelings (1998) argument, given that the short term consequences of a regulator's actions are more readily observable than the long-term consequences on investment, the regulator might have an incentive to set the price at a lower level.

Incentive for regulators to overregulate

An argument related to the incentive for regulators to overregulate is the 'tar baby' effect. Initially developed by McKie (1970, p. 9), the tar-baby argument is that regulators increase regulation to reduce distortions. That is, the regulator acknowledges distortions brought about by regulation, but then begins a quest to control them. Similarly, Kahn (2002, p. 36) described the effect as the 'the tendency of regulation, once undertaken, to become increasingly pervasive and thoroughgoing'. Sometimes, the quest to control a business might involve adding new layers of regulation in response to adjustments made by the regulated business:

> Each time the [regulatory] dike springs a leak, plug it with one of your fingers; just as a dynamic industry will perpetually find ways of opening new holes in the dike, so an ingenious regulator will never run out of regulatory fingers. (Kahn 1978, pp. 17–18)

Spann made a similar point:

> In their attempts to eliminate, or at least reduce, some of the distortions created by the original simple decision rule … regulators often find that they must continually extend

> their regulatory controls as firms make marginal adjustments to previously imposed constraints. (Spann 1975, p. 172)

Allgas Energy noted that in relation to ring fencing:

> … the cost to the gas part of the company of having to comply, the same way as we comply in electricity, becomes a big burden. We have to do big ring fencing reports. The intrusion gets more and more. We have intrusion into the regulatory accounts into the gas part of the business, which is extraordinary. You have to say, well, where are the costs and benefits of all this? It's costing Allgas a tremendous amount of money to comply with ring fencing and other requirements but, given the size of the business, it's just nonsensical. It's really a problem. (trans., p. 311)

Lack of incentives for regulators to reduce their costs

The gas industry funds some regulatory agencies (chapter 11). If businesses pay regulators' costs, there might be little incentive for regulators to minimise their costs. The Chamber of Commerce and Industry WA, in observing that the Office of Gas Access Regulation is able to recover the reasonable costs of access regulation in Western Australia from the gas industry, noted:

> Giving the regulator power to levy regulated industry to recoup costs creates an incentive structure that obviates the regulator's need to control costs.
>
> … By way of comparison, funding of the regulator's functions from consolidated revenue ensures that the normal budgetary scrutiny prevails. There is a strong incentive by the funding government to ensure that the regulator constrains costs and performs efficiently. (sub. 39, p. 2)

Potential for regulators to be captured

Regulatory agencies serve to maximise the national interest subject to their legislative mandates. In practice, there is a risk that administration of the regulatory regime might be influenced by other interests. This is sometimes referred to as regulatory capture and might occur in a number of ways.

First, regulators might be captured by the businesses they regulate (Stigler 1971). The regulators deal frequently with the businesses they oversee and might identify too closely with these businesses.

Second, regulators might feel constrained by the precedents set by their own past decisions. Goldfields Gas Transmission noted:

> A common theme that we hear from regulators is that they are constrained to what they can do by the precedents that they have got, and they say that the [Gas] Code does not enable them to do this. But generally, when you look for that restriction it's actually not

> a restriction written in the Code, it's their interpretation of the way they are honour bound to the precedents that have gone before them. (trans., p. 63)

Third, regulators might have their own personal objectives. Viscusi, Vernon and Harrington, quoting work by Wilson (1980), noted that the incentives of employees of regulatory agencies depend on the type of employee, and that understanding their motivations is important in explaining the policies that are implemented. In particular, they identified three kinds of employees:

> The *careerist* is an employee who anticipates a long-term relationship with the regulatory agency and whose major concern is that the regulatory agency continue to exist and grow. Not surprisingly, the careerists frown on deregulation. The *politician* envisions eventually leaving the agency for an elective or appointive position, with the regulatory agency a stepping stone for bigger and better things. Most commissioners are classified as politicians. Finally, the *professional* is more identified with certain skills than with the regulatory agency and strives to maintain professional esteem to allow career advancement. (Viscusi, Vernon and Harrington 2000, p. 311)

Fourth, regulators might be captured by populism, whereby they might make decisions that are popular, even if poorly founded. They might regulate, for example, where a large business is perceived to be profiteering, even if the action is objectively efficient (such as rewarding a past risky investment) (PC 2001e, pp. 63–4).

Fifth, regulators might have explicit objectives, for example, in the legislation establishing and governing the regulator, that differ from the objectives of the access regime (chapter 5). A regulator's institutional settings might convey a role of consumer advocate, or a regulator might perceive its role as balancing the regulatory bargain to achieve an outcome (Essential Services Commission of South Australia, sub. 3, p. 3).

Sixth, the consumer protection role of regulators might lead to a bias in favour of consumers in the short term, at the expense of economywide benefits or longer term considerations. The ACCC noted that, in principle, it is possible that the incentives faced by a regulator could lead to a bias in regulated investment returns that favours either regulated businesses or consumers:

> The incentives facing regulators is central to many arguments that regulation may discourage investment. For example, central to the [regulator] commitment issue is the assumption that regulators will act in the interests of consumers to *ex post* expropriate rents from producers. In contrast, Laffont and Tirole (1991) ['The politics of government decision making: a theory of regulatory capture', *Quarterly Journal of Economics*, vol. 106, no. 4, pp. 1089–127] undertake an analysis of a regulator that seeks to maximise personal income and is 'captured' by industry participants. Hence, the incentives regulators face can influence their ability to provide adequate returns,

> however the outcome is dependent upon the incentives regulators are assumed to face and the literature has proposed a number of alternatives. (sub. DR101, p. 65)

However, the widespread concerns expressed to this inquiry by service providers suggest that 'industry capture' of regulators has not occurred under the Gas Access Regime. Rather, there seems to be potential for the consumer advocacy role of regulators to bias regulatory decisions in favour of consumers at the expense of economywide benefits. KPMG noted:

> It is interesting that the possibility of 'regulatory capture' (the regulatory authorities being captured by the industry it regulates) does not seem presently to be an issue here in Australia. Whether there has been a 'populist capture' is indeed a valid question. (sub. 20, p. 12)

Consumer protection is often an important objective of regulators. For example, s.8(1) of the *Essential Services Commission Act 2001* (Vic) states:

> … the primary objective of the [Essential Services] Commission is to protect the long term interests of Victorian consumers ...

Similar wording is used in s.6(1)(a) of the *Essential Services Commission Act 2002* (SA) to guide the Essential Services Commission of South Australia.

It is notable that consumers are the only group explicitly recognised in the title of the ACCC. Nevertheless, the ACCC has stated that it also takes account of the interests of other groups:

> The ACCC promotes competition and fair trade in the market place to benefit consumers, business and the community. It also regulates national infrastructure services. Its primary responsibility is to ensure that individuals and businesses comply with the Commonwealth competition, fair trading and consumer protection laws. (ACCC 2003g)

Train (1991) observed that there is often a tendency for regulators to favour consumers:

> There is often a tendency for regulators, in an attempt to protect the public, to treat extraordinary losses and gains differently. For example, if a firm makes a decision that later proves to have been wrong (eg. to build a power plant that ends up being unneeded, or ends up costing much more than expected), there is a tendency to force the firm (namely, the shareholders) to bear the part of the cost of the 'mistake' rather than pass on the entire cost to the firm's customers. On the other hand, if the utility makes a decision that results in much greater profits than expected (eg. negotiates long-term contracts for the supply of inputs just before the spot price of these inputs unexpectedly skyrockets), then there is a tendency for the gains to be passed on to customers, because allowing the firm to retain the extra profits would result in the firm earning more than a 'fair' return. (Train 1991, pp. 96–7)

4.10 Overall assessment

The Commission considers there is still a case for an industry-specific access regime for the gas industry. The Gas Access Regime has generated benefits from increased third party access and lower prices for that access. However, these benefits have occurred along with significant costs to service providers, users and governments. A contributing factor to the level of costs appears to be the uncertainty associated with the wide discretion afforded to regulators. Importantly, the Commission also considers that the Gas Access Regime is also likely to be distorting investment decisions particularly in a market where competition is emerging.

Virtually all inquiry participants consider that improvements are warranted, including those participants that considered the benefits of the current regime outweigh the costs.

FINDING 4.7

The existing Gas Access Regime has deficiencies. Improvements are possible.

There is scope for improvement in a number of areas. Improvements proposed in subsequent chapters would result in an overall net benefit. Improving the specification of the Gas Access Regime objectives is discussed in chapter 5. Improving the coverage process would also ensure pipelines are regulated only where the benefits significantly outweigh the costs. Improvements to the coverage criteria and coverage process are discussed in chapter 6.

Improvements to the existing approach to regulation (access arrangements with reference tariffs) are discussed in chapter 7. Given the significant costs of the existing approach, there is scope to consider light-handed regulation (with lower costs) where the potential benefits from regulation are lower. Light-handed options are discussed in chapter 8 (and when to apply such regulation is discussed in chapter 6). Options to minimise the adverse effect of regulation on investment are examined in chapter 9. Improvements to ring fencing and associate contracts, administrative and appeal processes, and institutional arrangements are discussed in chapters 10, 11 and 12 respectively.

5 Objectives and objects clause

The current objectives of the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) stem from the 1997 Natural Gas Pipelines Access Agreement by the Australian, State and Territory Governments. Each jurisdiction's legislation that gives effect to the agreement incorporates these objectives and related factors and principles. The strengths and weaknesses of the objectives and related factors and principles are assessed in this chapter, together with recommendations for improvement.

5.1 Benefits of well specified objectives

Ministers, regulators, tribunals and the judiciary responsible for implementing and enforcing regulatory arrangements, are guided by objectives, often in the form of an objects clause. The more clearly specified the objectives, the more effective is the guidance to regulators. In its review of the national access regime (part IIIA of *Trade Practices Act 1974* [TPA]), the Productivity Commission noted that access regimes, to function efficiently, must have clear objectives that 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
- regulatory accountability. (PC 2001c, p. 124)

Regulatory accountability involves an assessment of whether regulators achieve the objectives. Clear objectives, with observable outcomes, therefore facilitate assessments of effectiveness.

The generic qualities and benefits of clear objectives, as enunciated in the Commission's review of part IIIA of the TPA, are relevant for the Gas Access Regime. Clear objectives improve the likelihood of:

- reducing administration and compliance costs of regulation
- reducing the scope for conflict and disputes
- achieving more efficient outcomes for the gas industry.

Decision makers facing conflicting objectives need to exercise discretion to assess the tradeoffs. In matters of law, the judiciary often has to weigh up a range of factors in making a judgment. However, the larger the number of conflicting objectives, the greater is the discretionary element involved in their resolution. As this tends to increase the potential for inconsistent judgments, there are advantages in narrowing the range of, and clearly specifying, objectives.

A recent survey of the objectives of competition policy in member countries of the OECD concluded that competition policy is often underpinned by a range objectives in addition to the encouragement of competition. The study found:

> The inclusion of multiple objectives, however, increases the risks of conflicts and inconsistent application of competition policy. The interests of different stakeholders may severely constrain the independence of competition policy authorities, lead to political intervention and compromise and adversely affect one of the major benefits of the competitive process, namely economic efficiency. (OECD 2003, p. 9)

5.2 Existing objectives

The Gas Access Regime, including the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) contain a range of objectives. These include overall objectives and more detailed factors and principles to guide Ministers, regulators, appeal bodies and the courts in their administration of the regime.

Natural Gas Pipelines Access Agreement

In 1997, representatives of Australian, State and Territory Governments signed the Natural Gas Pipelines Access Agreement and agreed to the Gas Code. The agreement's objectives are replicated in the italicised introduction to the Gas Code (box 5.1).

Gas Access Regime

The objectives in the Natural Gas Pipelines Access Agreement are included in the preamble to the legislation enacted by the Australian, State and Territory Governments, with one amendment to the fourth objective (d). The preamble to the legislation expands this objective as follows:

> (d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for the owners and operators of gas transmission and distribution pipelines and persons wishing to use the services of those pipelines. (*Gas Pipelines Access (South Australia) Act 1997)*

Box 5.1 Objectives in the Natural Gas Pipelines Access Agreement and the Gas Code

The purpose of the 1997 Natural Gas Pipelines Access Agreement and related Gas Code was to establish a uniform national framework for third party access to natural gas pipelines that:

(a) facilitates the development and operation of a national market for natural gas

(b) prevents abuse of market power

(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders

(d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users

(e) provides for the resolution of disputes.

Sources: 1997 Natural Gas Pipelines Access Agreement, p. 2; Gas Code, p. 1.

The objectives of the preamble to the Gas Pipelines Access Law (box 5.1, with the amendment) call for an access regime that 'promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders' and 'provides for rights of access to natural gas pipelines on conditions that are fair and reasonable'. These objectives are related to the Competition Principles Agreement (CPA) conditions for legislated third party access where 'access to the service is necessary in order to permit effective competition in a downstream or upstream market' (clause 6(1)(b)).

Although all these inclusions represent statements of objectives, the gas access legislation does not contain an 'objects clause' explicitly to give legal weight to an overarching regime objective.

Access arrangements

The Gas Access Regime makes a number of references to objectives, factors and principles that a regulator must take into account in performing its functions.

Factors for regulators to consider in assessing an access arrangement

Section 2.24 of the Gas Code provides guidance on the factors that a regulator must take into account when assessing a proposed access arrangement (box 5.2).

Box 5.2 Factors to be considered in assessing an access arrangement

Section 2.24 of the Gas Code lists the following factors that a regulator must take into account when assessing a proposed access arrangement:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline

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

(d) the economically efficient operation of the Covered Pipeline

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

(f) the interests of Users and Prospective Users

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

Guiding principles for setting reference tariffs

Under s.8.1 of the Gas Code, regulators are required to ensure that reference tariffs and reference tariff policies meet a number of objectives (box 5.3). Section 8.1 of the Gas Code gives the regulator discretion where objectives are in conflict.

Box 5.3 Guiding principles for setting reference tariffs

Section 8.1 of the Gas Code states that:

> A Reference Tariff and Reference Tariff Policy should 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
>
> (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.

Other sections of the reference tariff principles, in addition to s.8.1, provide guidance for the service provider and regulator on the method for determining a reference tariff (box 5.4). This guidance includes procedures and factors for estimating the values of parameters (for example, the initial capital base and the rate of return) used to determine a reference tariff.

Box 5.4 Additional considerations for setting reference tariffs

Other sections of the reference tariff principles, in addition to s.8.1, include principles and factors for the regulator to consider. The sample below are described in summary form:

- method for varying the reference tariff within an access arrangement period (price path, annual cost of service, among others) (s.8.3)
- total revenue, defined as total cost using one of three methodologies (cost of service, internal rate of return, and net present value) (s.8.4)
- principles for establishing the capital base (ss8.8–8.14)
  - initial capital base — existing pipelines (ss8.10–8.11)
  - initial capital base — new pipelines (ss8.12–8.13)
  - initial capital base — after expiry of an access arrangement (s.8.14)
- new facilities investment (s.8.15)
- forecast capital expenditure (s.8.20)
- capital contributions (by users) (s.8.23)
- capital redundancy (s.8.27)
- rate of return (s.8.30)
- depreciation schedule when the cost of service method is used (s.8.32)
- application of depreciation principles to internal rate of return and net present value methods (s.8.34)
- noncapital costs (s.8.36)
- allocation of revenue and costs between services (s.8.38)
- allocation of revenue and costs between users (s.8.42)
- use of incentive mechanisms (s.8.44)
- reference tariff principles not subject to periodic review (fixed principles) (s.8.47)
- assessment of compliance with s.8 (s.8.49).

Source: Gas Code.

Guiding principles for arbitrating a dispute

Section 6.15 of the Gas Code outlines the factors to consider when arbitrating a dispute between a service provider and a user about the terms and conditions of a covered pipeline. They are very similar to the dispute resolution principles set out in the CPA. They are also close to the factors to be considered in assessing an access arrangement (s.2.24 of the Gas Code — box 5.2). Sections 6.15(b) and (c) contain additional factors for the arbitrator to consider:

> (b) the costs to the Service Provider of providing access, including any costs of extending the Covered Pipeline, but not costs associated with losses arising from increased competition in upstream or downstream markets
>
> (c) the economic value to the Service Provider of any additional investment that the Prospective User or the Service Provider has agreed to undertake. (Gas Code, s.6.15)

Section 6.15(h) — 'benefit to the public from having competitive markets' — differs from the similar factor in s.2.24, which refers to the public interest, including the public interest in having competition in markets. In s.2.24, the public interest is a broader concept that might include other factors, such as equity, in addition to competitive markets.

Other legislation

Under the Gas Access Regime, each jurisdiction can have its own regulator of distribution networks (and of transmission pipelines in Western Australia). In applying the Gas Access Regime, these regulators might have additional State- or Territory-level responsibilities with additional objectives set out in their own enabling legislation.

In most cases, the objectives of regulators involved in applying the Gas Access Regime include:

- promoting competitive markets
- facilitating efficiency in supply of services
- protecting the interests of consumers.

Some regulators might also be required to take into account factors such as the social impact or environmental effects of their determinations.

The objectives of the Essential Services Commission in Victoria are an example of the general objectives of State regulators (box 5.5). The Victorian Department of Infrastructure noted:

> This model in which the regulator has two tiers of guidance — a primary objective and facilitating objectives — permits the potentially competing advice from the facilitating objectives to be weighted and reconciled against an overarching criterion. (sub. 71, p. 10)

Box 5.5 **Objectives of the Essential Services Commission**

Under the Gas Access Regime, the Essential Services Commission is responsible for approving access arrangements in Victoria for covered distribution networks. The *Essential Services Commission Act 2001* (Victoria), has the following objectives:

(1) In performing its functions and exercising its powers, the primary objective of the Commission is to protect the long term interests of Victorian consumers with regard to the price, quality and reliability of essential services.

(2) In seeking to achieve its primary objective, the Commission must have regard to the following facilitating objectives:

- (a) to facilitate efficiency in regulated industries and the incentive for efficient long-term investment
- (b) to facilitate the financial viability of regulated industries
- (c) to ensure that the misuse of monopoly or non-transitory market power is prevented
- (d) to facilitate effective competition and promote competitive market conduct
- (e) to ensure that regulatory decision making has regard to the relevant health, safety, environmental and social legislation applying to the regulated industry
- (f) to ensure that users and consumers (including low-income or vulnerable customers) benefit from the gains from competition and efficiency
- (g) to promote consistency in regulation between States and on a national basis.

(3) Without derogating from sub-sections (1) and (2), the Commission must also perform its functions and exercise its powers in such a manner as the Commission considers best achieves any objectives specified in the relevant legislation under which a regulated industry operates.

Source: *Essential Services Commission Act 2001* (Victoria), s.8.

With regard to access to gas transmission and distribution infrastructure, the Gas Access Regime has primacy over other potentially overlapping legislation. Objectives outside the Gas Access Regime are pursued through other mechanisms.

5.3 Assessing the existing objectives

It is clear from the preceding section that there are many references in the Gas Access Regime documentation to objectives, and there are many different objectives. To some extent, this is a consequence of the negotiation process at the time the Gas Access Regime was established. The range of objectives resulted from an attempt to balance the different interests of jurisdictions, pipeline owners and users to obtain agreement.

Conflicting objectives

Some of the objectives, factors and principles embodied in the Gas Access Regime are potentially in conflict. Regulators not only need to interpret the meaning of the objectives, but also implicitly or explicitly attach weights to them. The Essential Services Commission observed:

> … there is no single high level objective that encapsulates the principal purpose of the [Gas] Code. There is also a lack of clarity about the status of the objectives set out in the introduction of the Gas Code and their interaction with other objectives and principles set out elsewhere in the Code. (sub. 51, p. 2)

The Australian Gas Association (AGA) noted that the guiding principles lack clarity and have the scope for conflict:

> There is a lack of clear guidance in the Gas Access Regime about the principles which should underpin access pricing determinations. This lack of clarity is exacerbated by a variety of sections of the national Gas Code which set out a range of conflicting possible pricing principles. Sections 2.24 and sections 8.1–8.2, for example, set out no less than 18 different factors and considerations which must inform access pricing determinations. State-based legislation establishing independent regulatory authorities frequently refer to additional principles that must be taken into account in pricing determinations. (sub. 13, p. 26)

The Supreme Court of Western Australia’s judgment in the Epic Energy case (*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231) concluded that the Gas Code contains potentially conflicting ‘considerations and objectives’, particularly, in ss2.24, 8.1, 8.10 and 8.11 (box 5.6).

Ergas argued that the Epic Energy case demonstrated:

> … the [Gas] Code … 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. (Ergas 2003a, p. 15)

The Australian Gas Light Company noted that the conflicting objectives have resulted in uncertainty for regulated businesses and access seekers:

> The numerous objectives, some of which conflict, mean there has been a lack of clear guidance with the effect that there has been uncertainty and a lack of clarity for regulated businesses and existing and potential users. (sub. 32, p. 10)

The Western Australian Office of Gas Access Regulation drew the link between the complexity and lack of clarity of the objectives and factors to be taken into account, on the one hand, and the resultant uncertainty and cost on the other:

> I guess we would draw attention to the fact that there are no overriding objectives and also the very complex nature of the [Gas] Code. That really is brought about by the complex interrelationship between principles and factors to be taken into consideration, in particular sections 2.24, 8.1, 8.10 and 8.11 of the Code. I think as a general comment, our experience suggests that the Code does lack clarity and introduces uncertainty and with that, of course, also the opportunity for debate and the consequential impact that that has on timeliness and on cost. (trans., p. 80)

Box 5.6 **The Epic Energy case**

In November 2001, the Supreme Court of Western Australia heard an application from Epic Energy regarding a draft decision by Dr Ken Michael (the Independent Gas Pipelines Access Regulator) on Epic Energy's proposed access arrangement for the Dampier–Bunbury pipeline. Epic Energy was principally concerned with the regulator's decision on the value of the initial capital base of the pipeline and estimate of reference tariffs. In summary, Epic contended that the regulator had misconstrued ss2.24 and 8 of the Gas Code; and had erred in law by failing to account for relevant factors and by taking into account irrelevant factors.

The Supreme Court of Western Australia's 2002 judgment (*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231) highlighted issues important to the guiding principles for reference tariffs. It was noted that the Gas Code contains potentially conflicting 'considerations and objectives', particularly in ss2.24, 8.1, 8.10 and 8.11. However, the Court did not rule on the precise interaction (such as the relative weights) of these conflicting considerations and objectives.

The Court considered:

> … the scheme of the [Gas Pipelines Access] Act and the [Gas] Code is to leave this potential conflict which, in part, is between the interests of a service provider in achieving a return on its investment in the pipeline and the interests of users or consumers in achieving a lower price and indeed, perhaps, in the achievement in the public interest of greater competitiveness or the effects of competition, to be resolved by the regulator in accordance with the Act and the Code and the circumstances of each particular case. (Supreme Court of Western Australia 2002, para. 185)

The factors in s.2.24 should guide the regulator in determining, if necessary, how to best reconcile the guiding principles in s.8.1.

In practice, it is common to give regulators (and the courts) some discretion to take into account factors that might vary from case to case. However, in the case of the Gas Access Regime, the Commission has concluded there are too many objectives, some of which are in conflict and not directly relevant to the overall policy objective of the regulation.

Regulator discretion

The Gas Code gives regulators a high degree of discretion to resolve conflicts among objectives and interest groups (final paragraphs of ss2.24 and 8.1). Section 8.1 states that the regulator, where any of the objectives in the section are in conflict, may determine how to best reconcile them or which should prevail.

The Epic Energy case (para. 136) indicated that the regulator, in exercising discretionary powers under s.8.1, should be guided by the factors outlined in s.2.24. The Court did not rule on the precise relationships among the conflicting considerations and objectives by assigning relative weights, for example. Indeed, the Court stated that these matters were to be resolved by the regulator (box 5.6).

Duke Energy International noted concern about the differences among the factors in ss2.24 and 8.1. It argued that the Court's ruling in the Epic Energy case:

> … sends a strong message that there is now a greater need to resolve contentious and conflicting sections that convey high level guidance on the intent of regulation under the [Gas] Code. (sub. 21, p. 14)

In determining the weight to be attached to each object, principle or factor, regulators are likely to require significant levels of information. Goldfields Gas Transmission noted:

> … the apparent need under the Gas Code for an extremely high information requirement in order for regulators to assess and make subjective judgments concerning all manner of details, ranging from minor contractual arrangements to parent company capital structure. (sub. 18, p. 13)

Regulators being required to apply discretion also has implications for transparency. It might not be clear, for example, how regulators tradeoff objectives or decide on a relative weighting when balancing conflicting objectives, or what factors they consider in assessing public interest objectives.

Some inquiry participants advocated a more prescriptive regime that reduces regulator discretion by ranking or assigning weights to objectives. Worsley Alumina suggested:

> … it is desirable and appropriate that the [Gas] Code assign relative, if not absolute, weight to these [objectives] by, say, ranking the objectives or by recommending which objectives should prevail in which circumstances. (sub. 5, p. 3)

On the other hand, the Essential Services Commission of South Australia argued that the discretion available to regulators provides the flexibility necessary for tradeoffs between objectives to the benefit of both the industry and consumers. It agreed that certain objectives of the current Gas Access Regime are in conflict and might create uncertainty, but it:

> … does not perhaps share the same level of disquiet as other industry participants in respect of this issue, as, in its view, making discretionary 'tradeoffs' between such objectives permits a more flexible approach to regulation than might otherwise be the case. Indeed, it is the [Essential Services Commission of South Australia's] position that a system permitting a degree of flexibility in approach to regulation is likely to be more beneficial to both the industry and consumers: that is exactly why an independent regulator exists in the first place. (sub. 3, p. 2)

The Energy Markets Reform Forum took a similar position:

> … the Gas Code, as presently drafted, provides a balance between the competing interests of various parties. It provides regulators with sufficient flexibility, defined parameters but with an ability to exercise judgment. (sub. 30, p. 17)

In the Commission's view, the objectives of the Gas Access Regime are not well specified in the enabling documentation. In particular, there are too many objectives, some potentially in conflict with insufficient guidance to regulators on how to weigh up the tradeoffs. In addition, the consequential explicit capacity of the regulator to apply virtually unlimited discretion carries with it its own disadvantages, such as reduced transparency and increased uncertainty. The Gas Access Regime's effectiveness (and the regulator's task) would be assisted by better specification of the objectives in the relevant documentation. This might involve the insertion of a single overarching objective, the removal of unnecessary objectives spread throughout the documentation, and modification of other factors to make them consistent with the overarching objective.

FINDING 5.1

There is a need to specify more clearly the objectives of the Gas Access Regime.

5.4 Need for an overarching objective

The absence of an overarching objects clause was noted by the Western Australian Government:

> There is no overarching, definitive objective of the [Gas] Code and [Gas Pipelines Access] Law, and the pricing principles are dispersed, overlap and may cause ambiguity.
>
> A clear set of objectives would provide greater certainty for infrastructure owners, access seekers, investors and other interested parties, and provide clarity for decision makers, and enhance transparency and timeliness with respect to decision making. (sub. 70, p. 7)

Several regulators supported the concept of an overarching objective. The National Competition Council considered:

> … the introduction of a single, clear objects clause coupled with a requirement that the regulator have regard to that objects clause, together with the introduction of a single national regulator, will go some way to addressing the issues of uncertainty raised by the Epic decision. (sub. 57, pp. 63–4)

The Victorian Essential Services Commission commented that the Gas Access Regime would benefit from:

> - establishing of clear overarching objective in the Gas Code, and clarifying the status of other objectives and principles in the operational provisions of the Code
> - basing the Gas Code's principal objective on the concept of economic efficiency, as distinct from other objectives such as preventing monopoly abuses and promoting the natural gas market. (sub. 51, pp. 21–2)

However, the Australian Competition and Consumer Commission did not consider an overarching objects clause was a priority:

> I take the point that … generally one clear objective is preferable for a piece of regulation like the Gas Code. … I just don't think it would make a big difference, or make any difference at all to what we do or the processes that we are responsible for. (trans., p. 339)

A number of industry participants supported an overarching objects clause. For example, the AGA (sub. 13, p. 20), Alinta (sub. 36, p. 4), Allgas Energy (sub. 25, p. 9), Duke Energy International (sub. 21, p. 13) and TXU Australia (sub. 11, p. 11) noted that a clear objects clause within the Gas Access Regime would:

- enhance the consistency of regulatory decisions and reduce contradictory guidance and regulatory error
- ensure regulatory authorities, when making access decisions, adequately consider the medium term interests of existing and potential gas users
- give greater certainty to asset owners, access seekers and other interested parties
- facilitate efficient commercial negotiation on terms and conditions of access
- increase regulatory accountability.

The Commission considers that a single clearly specified objects clause would improve the effectiveness of the Gas Access Regime. It would guide regulators and provide greater certainty for infrastructure owners and access seekers. It would identify the priority of the regime and carry more weight than the list of objectives in the existing preamble to the legislation. It should reduce the conflict among objectives.

FINDING 5.2

The incorporation of an overarching objects clause into the Gas Access Regime legislation would enhance the effectiveness of the regime.

Subsidiary factors and principles to provide guidance to regulators in decisions about coverage and access arrangements, should flow from and be consistent with an overarching objects clause. Clear guidance for regulators in relevant documentation would also assist the delivery of effective regulation. The Victorian Department of Infrastructure pointed to the benefits of clarifying the guidance for regulators:

> … this is likely to reduce regulatory uncertainty, and also reduce the scope for disputation and hence the costs incurred by the various parties in administering or complying with the regime. (sub. 71, p. 10)

5.5 Objectives

Economic efficiency

The Gas Access Regime is part of Australia's competition policy and law framework and is complementary to part IIIA of the TPA, along with other industry-specific access regimes (such as for the telecommunications sector) that target the problem of the supply of and access to bottleneck facilities. In considering an overarching objects clause, guidance can be found in the Commission's review of part IIIA of the TPA (PC 2001c) and the Australian Government's response to that review (Costello 2004).

Part IIIA of the TPA does not have its own objects clause. However, the TPA has an objects clause that applies to the whole of the Act and therefore applies to part IIIA. The TPA objects clause is to 'enhance the welfare of Australians through the promotion of competition and fair trading and provision for consumer protection'.

In its review of the national access regime, the Commission considered that the objects clause for the TPA was too broad and focused on promoting competition. Competition was seen by the Commission as a means to an end and not an end in itself. The promotion of competition is only desirable if it promotes efficiency. Therefore, the Commission recommended that a specific objects clause be incorporated into part IIIA, which had an explicit efficiency objective reflecting both short-term and long-term considerations (box 5.7). The intention was to change the emphasis from promotion of competition to promotion of economic efficiency and to ‘seek to promote efficient use of essential infrastructure in a way that does not discourage efficient investment’ (PC 2001c, p. 128).

The Australian Government has responded to the Commission’s recommendation by proposing to include an objects clause in the national access regime (Costello 2004). However, the wording differed from the Commission’s recommendation in relation to clause (a) by adding ‘thereby promoting effective competition in upstream and downstream markets’, in addition to the statement about the promotion of economic efficiency (box 5.7). The Government also inserted the words ‘operation and’ into clause (a).

The Australian Government’s response to the Commission’s part IIIA review noted:

> The promotion of economic efficiency is a fundamental objective of competition policy. The first objective explicitly recognises the importance of fostering efficient investment in new essential infrastructure, while at the same time encouraging the efficient use of existing facilities through innovation and productivity improvements. (Costello 2004, p. 3)

Box 5.7 **Proposals for an objects clause for part IIIA of the TPA**

In its review of part IIIA of the TPA, the Commission recommended the following objects clause:

(a) promote economically efficient use of, and investment in, essential infrastructure services; and

(b) provide a framework and guiding principles to discourage unwarranted divergence in industry-specific regimes.

The Australian Government’s response to the review proposed the following objects clause:

(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.

Sources: PC 2001c; Costello 2004.

An objects clause focused on efficiency would be consistent with the rationale of the Gas Access Regime. The problem being addressed by the regime is the potential for the exercise of market power by owners of transmission pipelines and distribution networks because of the natural monopoly characteristics of pipelines. The market power could be used either to deny access to potential competitors or charge monopoly prices. This might lead to economic inefficiencies and the possibility that access regulation could reduce these inefficiencies by facilitating competition and reducing monopoly pricing.

Long term

The Commission's telecommunications inquiry report (PC 2001e) recognised the importance of incorporating a long-term dimension into the objects clause. It was regarded as important to avoid the pitfall of setting low access prices in the short run (to the short-term benefit of consumers), but provoking a long-run diminution of supply that would result in foregone future consumption (PC 2001e, p. 257). An objects clause that is explicit about investment is probably a suitable way of ensuring a long-term focus.

Reductions in access prices benefit current users and might stimulate the demand for and use of pipeline services. However, the returns to pipeline owners are reduced, which might deter investment and thereby adversely affect future users. The objective should seek a balance between these short-term and longer term considerations. The Hilmer Committee recognised this balance, and suggested that the following principle might be appropriate for national competition policy:

> The promotion of long-term economic efficiency, taking into account the desirability of fostering investment, innovation and productivity improvement, and the desirability of discouraging a person who has a substantial degree of power in a market from using that power to set prices above efficient levels. (Hilmer Committee 1993, p. 279)

Upstream/downstream

The efficiency objective encompasses the objective of promoting competition in upstream and downstream markets. The Gas Access Regime would not promote competition in related markets without an efficiency improvement in the pipeline infrastructure.

Inclusion of the phrase 'thereby promoting effective competition in upstream and downstream markets' (as has been decided by the Australian Government for clause (a) of the objects clause for the national access regime) runs the risk that competition would be regarded as a major objective in itself, rather than as a mechanism by which the benefits of pipeline efficiency are distributed to other sectors. However, the word 'thereby', rather than implying a causal relationship, could also mean 'in doing so'. Under this interpretation, promoting competition would not erode the primacy of the efficiency objective. It implies that promoting competition in a related market is a flow-on effect of promoting efficiency in the gas pipeline market, rather than the end objective.

The Australian Government has consulted with other jurisdictions, as discussed in the introduction to its response to the Commission's review of the part IIIA legislation:

> The Australian Government has consulted with all jurisdictions in developing its final response to the Commission's recommendations. The Australian Government appreciates the constructive comments and suggestions by jurisdictions, which have improved and clarified the final response in a number of areas. (Costello 2004, p. 2)

It is desirable for the objects clause in the Gas Access Regime and other industry-specific regimes to be consistent with that of the national access regime. This in fact is indicated in clause (b) of the objects clause for the national access regime recommended by the Commission and endorsed by the Australian Government.

Clauses 6(1) and 6(3) of the CPA state that one of the conditions for establishing legislation for third party access to infrastructure facilities is that 'access to the service is necessary in order to permit effective competition in a downstream or upstream market' (box 5.8). An objects clause that includes a reference to downstream and upstream competition would be consistent with this.

Box 5.8 **Competition Principles Agreement — conditions for establishing legislated third party access to infrastructure**

Clause 6(1) of the CPA states:

> Subject to subclause (2), the Commonwealth will put forward legislation to establish a regime for third party access to services provided by means of significant infrastructure facilities where:
>
> (a) it would not be economically feasible to duplicate the facility
>
> (b) access to the service is necessary in order to permit effective competition in a downstream or upstream market
>
> (c) the facility is of national significance having regard to the size of the facility, its importance to constitutional trade or commerce or its importance to the national economy
>
> (d) the safe use of the facility by the person seeking access can be ensured at an economically feasible cost and, if there is a safety requirement, appropriate regulatory arrangements exist.

Clause 6(3) of the CPA states:

> For a State and Territory access regime to conform to the principles set out in this clause, it should:
>
> (a) apply to services provided by means of significant infrastructure facilities where:
>
> (i) it would not be economically feasible to duplicate the facility
>
> (ii) access to the service is necessary in order to permit effective competition in a downstream or upstream market
>
> (iii) the safe use of the facility by the person seeking access can be ensured at an economically feasible cost and, if there is a safety requirement, appropriate regulatory arrangements exist
>
> (b) incorporate the principles referred to in subclause (4).

For the promotion of competition in upstream and downstream markets to be 'effective' it must induce increased efficiency in these markets. As noted by the Hilmer Committee:

> Competition policy is not about the pursuit of competition per se. Rather, it seeks to facilitate effective competition to promote efficiency and economic growth … (Hilmer Committee 1993, p. xvi)

Effective competition and related concepts (such as workable competition used by some, which is discussed in chapter 7) imply a realistic concept of competition where some degree of market power might be present, in contrast to a theoretical ideal of 'perfect' competition which does not replicate real-world market behaviour.

If access regulation is successful in promoting economically efficient use of, and investment in, pipeline infrastructure, then users of the pipeline services should be able to compete more effectively in upstream, downstream or related markets. This should stimulate efficiency improvements in these markets, prompted by competitive responses from other incumbent firms in the markets.

Other

There are a variety of other possible objectives of competition policy, apart from economic efficiency. A joint study by the World Bank and OECD (1999) on competition law and policy noted a spectrum of views on the objectives of competition policy, ranging from *economic efficiency* at one end of the spectrum to *public interest* at the other end. Public interest is a relatively broad concept embodying social factors that are inherently difficult to quantify and 'loaded with value judgements' (World Bank and OECD 1999, p. 1).

The World Bank and OECD study concluded:

> This overview of the different objectives of competition policy indicates that in most jurisdictions the basic objectives are to maintain and encourage competition in order to promote efficient use of resources while protecting the freedom of economic action of various market participants. (World Bank and OECD 1999, p. 8)

Suggestions by inquiry participants on what the objects clause should contain drew from, and added to, the Commission's recommendations in its part IIIA report (PC 2001c) and the Australian Government's response (Costello 2004) to those recommendations.

The AGA considered that the objectives of the Gas Code should be to:

- promote the economically efficient operation and use of, and investment in, essential infrastructure services, consistent with that which would occur in a

> workably competitive market, thereby promoting effective competition in upstream and downstream markets
>
> - provide a framework and guiding principles for commercial arrangements and regulatory determinations
> - not to seek to replicate outcomes which would occur in a perfectly competitive market. (sub. 13, p. 25)

The National Competition Council submitted that the best approach for the objects clause was to have the single objective of economic efficiency:

> The object of the Gas Access Regime and Gas Code is to promote the economically efficient operation and use of, and investment in, gas distribution and transmission pipelines. (sub. 57, p. 10)

Some users, such as Orica and the Energy Markets Reform Forum, the latter a major users group, supported adding an efficiency objective to the existing objectives in the preamble and the introduction of the Gas Code. The Energy Markets Reform Forum recommended:

> … that the Gas Code have a new objects clause inserted, which combines clear economic efficiency objectives with the existing preamble … (sub. 42, p. 3)

BHP Billiton, which is a producer and consumer of gas nationwide and hence a major user of the pipeline infrastructure, commented:

> The adoption of an objects clause in the Gas Pipelines Access Law or [Gas] 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 … (sub. 26, p. 114)

Newmont Australia, a mining company and user of gas via the Goldfields Gas Pipeline, contended:

> … the [Gas] Code needs a better objectives clause and one which requires good consumer and public policy outcomes, and the control of market power by monopolies or oligopolies, rather than the weak 'promotion of competition' objective, as this is too vague and does not necessarily produce consumer benefits. (sub. 50, p. 18)

Proposed objects clause

In recent years, there has been considerable deliberation on how best to specify the objectives for regulatory intervention within the broad sweep of competition policy. The Commission considers it important to draw on these deliberations in proposing an overarching objects clause for the Gas Access Regime.

In particular, the Commission sees benefits in basing its proposal on the Commission's review of part IIIA of the TPA and the Australian Government's response to that review. The proposal would also need to be consistent with the CPA. On balance, consistency with part IIIA and the CPA is more important and outweighs the risk that the clause 'thereby promoting effective competition in upstream and downstream markets' could possibly erode the primacy of the efficiency objective. These considerations lead to an overarching objects clause that focuses on efficiency and investment, with a reference to promoting competition in upstream and downstream markets. If it were to emerge that the risk was significant that the clause 'thereby promoting effective competition in upstream and downstream markets' could erode the primacy of the efficiency objective, consideration would then need to be given to dropping this clause from the overarching objects clause in part IIIA and the Gas Access Regime.

Feedback on the objects clause proposed in the draft report revealed the importance of removing ambiguity in the interpretation of 'To promote the economically efficient use of, and investment in, the services of pipelines …'.

The Australian Pipeline Industry Association was concerned about the possibility that 'efficient use' could result in regulators requiring short-term marginal cost pricing of spare capacity at the cost of discouraging investment in the longer term. It considered:

> … that the efficient use of transmission pipelines should be subordinate to the second objective of achieving efficient investment in infrastructure.
>
> Failure to clarify the relative importance of these considerations could result in conflicts arising between the concepts. (sub. DR100, p. 14)

Enertrade was also concerned about the balance between 'economically efficient use of, and investment in, … pipelines' implied by the formulation of the objects clause in this inquiry's draft report:

> Enertrade remains deeply concerned that this formulation will be interpreted narrowly so that 'efficient' is taken to require conditions where price equals short-run marginal cost rather than focusing on long-term outcomes. Also, it is not clear that the proposed construction ensures that investment must be efficient. (sub. DR98, p. 4)

BHP Billiton had a different perspective from the pipeline service providers:

> As its stands, [the draft] recommendation … could be taken to read that a key objective of the [Gas] Code is 'to promote … investment'. However, if economically efficient use of infrastructure, [and] upstream and downstream competition is promoted by the Code, investment should also be promoted. The objective of regulation is to 'facilitate', and not 'promote' investment … Unless this reference to investment is removed from the objects clause, it will give the impression of being 'pro-investors' but not necessarily pro-shipper or pro-customer. (sub. DR96, p. 36)

The intention of the Commission's formulation of the objects clause in both its review of the national access regime (PC 2001c) and its draft report for this inquiry, and the Australian Government's intention in its response to the review of the national access regime (Costello 2004), was that 'economically efficient' should apply to investment in, as well to use of, facilities.

However, the Commission acknowledges the views of industry participants that in these formulations of the objects clause, some might possibly apply 'economically efficient' to 'the use of' but not to 'investment in' pipelines. The clause in the draft report for this inquiry could be interpreted to 'promote … investment' rather than 'promote … economically efficient investment'.

To give clarity to the objects clause of the regime and ensure a balance in the application of economic efficiency to the operation and use of, and to the investment in, pipelines, it is proposed that the phrase 'economically efficient' be included before both 'operation and use of' and 'investment in' pipelines, while retaining the basic formulation of the proposed objects clause for the national access regime.

RECOMMENDATION 5.1

The following overarching objects clause should be incorporated into the Gas Access Regime, with the wording consistent with the Australian Government's proposed objects clause for the national access regime:

> ***To promote the economically efficient operation and use of, and economically efficient investment in, the services of transmission pipelines and distribution networks, thereby promoting effective competition in upstream and downstream markets.***

Elaboration of the objects clause

In response to the draft report for this inquiry, interested parties requested further clarification of the efficiency and competition concepts included in the objects clause. The Institute of Public Affairs commented on the different views about these concepts (sub. DR89, pp. 1–2). The Australian Pipeline Industry Association also urged the Commission to provide clear guidance as to its interpretation of efficiency (sub. DR100, pp. 13–14). The Australian Gas Light Company noted:

> We support the proposed objects clause but believe that the Commission's intent could be better achieved by providing further definition or guidance as to the interpretation of key terms (such as economic efficiency and economically efficient investment). (sub. DR84, covering letter, p. 2)
>
> … it is important that there be a clear and common understanding of concepts such as:

- ‘economically efficient use of’ and ‘economically efficient investment in’ the services specified in the clause
- what might be involved in ‘promoting’ these outcomes
- interpretation of the (presumed) causal link between efficient pipeline or network use and investment and ‘the promotion of effective upstream and downstream competition’. (sub. DR84, p. 2)

The Australian Pipeline Industry Association also offered its interpretation of ‘efficiency’ and emphasised longer run dynamic aspects:

> APIA [Australian Pipeline Industry Association] wishes to clarify its perception of the meaning of ‘efficient’ in the current context. APIA notes that the concept of ‘efficient cost’ that has inspired much of the regulatory activity is anything but efficient in the long run in the way it has been applied. In APIA’s view, the concept of ‘efficient’ must be considered in the long run to incorporate dynamic aspects and fundamentally involves ensuring that the regulatory system does not distort investment incentives. Given the uncertainty and scope for confusion over this term, APIA believes that the Commission should provide clear guidance as to its interpretation of this term. (sub. DR100, p. 14)

Interpreting promotion of economic efficiency

There are several distinct types of economic efficiency, as recognised by the AGA:

> Traditionally, concepts of economic efficiency have been subdivided into three elements: productive (or technical efficiency), allocative efficiency, and dynamic efficiency. (sub. 13, p. 53)

The Hilmer Committee described these elements of efficiency as follows:

> - Technical or productive efficiency … is achieved where individual firms produced the goods and services that they offer to consumers at *least cost*.
> - Allocative efficiency is achieved where resources used to produce a set of goods and services are allocated to their highest valued uses (that is, those that provide the greatest benefit relative to costs).
> - Dynamic efficiency reflects the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities. (Hilmer Committee 1993, p. 4)

In regard to the proposed objects clause for the Gas Access Regime, the concept of efficiency in ‘economically efficient operation and use of, and economically efficient investment in, the services of transmission pipelines and distribution networks’ embodies the following aspects:

- Optimal allocation of resources to satisfy consumer demands for pipeline services (allocative efficiency).

- Maximum utilisation of pipeline capacity (an element of productive efficiency).
- Minimum operating cost per unit of throughput for a given quality of service (an element of productive efficiency).
- Maximum benefits from productivity improvements over time (dynamic efficiency).

In general terms, the planning and operation of a pipeline takes place in a dynamic world of constantly changing circumstances and unpredictable events. For example, consumer demands can fluctuate in unanticipated ways and the allocation of resources cannot be adjusted instantaneously. Also, maximum utilisation of pipeline capacity might need to include some spare capacity to allow for unforeseen and temporary increases in demand.

Because of the inherent uncertainty of supply and demand conditions, it is not possible to operationalise ‘efficiency’ in a definitive way. It is, however, appropriate for access policies to seek to move the pipeline services market towards the above broad efficiency goals. Regulatory intervention would only be beneficial where there was confidence that significant inefficiencies existed and that these could be reduced (taking into account the costs of intervention).

The operation of market forces, including price signals in relation to pipeline services, is a key mechanism for promoting all aspects of efficiency in the gas pipeline industry. As noted by the Hilmer Committee (1993, p. 4), effective competition can enhance all elements of efficiency. If there is a competitive environment which constrains the exercise of market power by gas pipeline service providers, then the pricing and investment behaviour of these providers should encourage efficient allocation of resources, improvements in work practices and productive use of inputs, and other innovations.

In the absence of an effective competitive environment, well designed regulatory intervention can encourage the various forms of efficiency primarily by the implementation of pricing principles and market rules. However, it is particularly important to recognise the limitations of regulatory intervention in achieving the efficiency benefits that would preferably be obtained by effective competition.

Also, the objective is to *promote* or improve economic efficiency rather than to arrive at a undefinable level of efficiency, which is impractical.

Promotion of effective competition in related markets

Increased pipeline efficiency might be associated with increased access to pipeline services by third parties, and hence improved availability, and/or lower transportation price, of gas for downstream users. Access to markets by upstream suppliers should also be improved. The price paid for gas by end users might be affected by changes in the price of the gas at its source, as well as changes in the price of transporting the gas.

The complexity of the market adjustments highlights the difficulties of measuring the effects of intervention on efficiency and competition. Making *judgments* about improvements in efficiency and competition might be necessary in addition to available *quantitative* measures. For example, an increase in the competitive environment might involve increasing the potential for downstream gas retailers to contest electricity markets — an improvement which is more difficult to measure than an increase in the number of market participants because of new gas retailers gaining access to the market.

The promotion of competition in related markets is the means by which the benefits of pipeline efficiency improvements are transmitted to other parts of the gas supply chain, to other industries and to final consumers. In this way, the promotion of pipeline efficiency leads to economywide efficiency improvements.

The Victorian Essential Services Commission emphasised the importance of the ultimate goal of improving economywide efficiency:

> … the essential policy goal of gas pipeline access regulation should be to promote efficiency (through enhanced competition) in related markets and ultimately in the economy as a whole. (sub. DR112, p. 6)

Objects clause in the context of coverage and regulation decisions

The overarching objects clause should provide the guiding principle with which other, second tier, criteria would need to be consistent. That is, coverage criteria and guidance on deciding the form of regulation (chapter 6), and guidance for designing access arrangements (chapter 7), should flow from this objective.

Coverage

The scope for regulatory intervention to increase pipeline efficiency depends on the extent of competition faced by the service provider, and other factors that might be acting as a constraint on its exercise of market power. The case for coverage varies from pipeline to pipeline.

The extent of the promotion of efficiency of pipeline services that would result from the intervention is indicated by the extent of the resultant promotion of competition in related upstream or downstream markets. This is assessed under one of the criteria for coverage (promote a material increase in competition) discussed in chapter 6.

The objective of efficiency improvement is also embodied in another coverage criterion (the public interest test), which involves a judgment about all the economic costs and benefits of coverage compared with leaving the pipeline uncovered.

Form of regulation

The Commission is proposing two alternative regulatory options for covered pipelines, one involving access arrangements with reference tariffs, and the other a light-handed monitoring approach (chapters 6 and 8).

Selection of the form of regulation should be based on maximising economic efficiency, in accordance with the objects clause. The Commission is proposing an assessment of net economic benefits to determine the more appropriate regulatory option. The choice would depend on which form of regulation generates greater net benefits. The reference tariff option would be applied only when it was clear that it would generate net benefits markedly above those that would accrue from the monitoring option.

Access arrangements with reference tariffs

It is recommended in chapter 7 that the regulator should apply a defined set of pricing principles in the situations where it has been decided that an access arrangement with reference tariffs is necessary. The recommended pricing principles are formulated to promote efficient use of, and investment in, pipelines, and provide incentives for productivity improvement.

Monitoring

Monitoring relies primarily on the market to provide the incentives to promote efficiency. The threat of regulation involving access arrangements with reference tariffs in the future is also an incentive to be efficient. While the objects clause covers monitoring, the regulator should not use the clause to go beyond the functions specified in chapter 8.

Requirement for decision makers to take account of the objects clause

In its review of the national access regime, the Commission noted:

> … that the objects clause should not simply be viewed as extrinsic material to be referred to only when the meaning of a constituent provision of part IIIA is unclear. Rather, it should condition the interpretation of relevant provisions of part IIIA … (PC 2001c, p. 136)

The Commission included a recommendation requiring decision makers to have regard to the objects clause. This recommendation was endorsed by the Australian Government (Costello 2004, p. 4).

The objects clause for the Gas Access Regime provides guidance for Ministers, various regulatory bodies, arbitrators and the courts and merit review bodies, and should be taken into account in their decisions.

RECOMMENDATION 5.2

For decisions about coverage, the form of regulation and regulated access terms and conditions, the relevant decision maker should be explicitly guided by the overarching objects clause.

5.6 Consequential revisions

The insertion of an overarching objects clause (recommendation 5.1) requires an assessment of the appropriateness of retaining the references to objectives in the preamble to the Gas Pipelines Access Act and the introduction to the Gas Code.

The first three listed objectives in the preamble to the legislation (relating to the development of a national market for natural gas, preventing abuse of market power and promoting a competitive market for natural gas) are all valid objectives in their own right. The question arises, however, as to whether they need to be explicitly listed as objectives for the Gas Access Regime in circumstances of there being an overarching objective as prescribed by recommendation 5.1. This overarching objective, in effect, encapsulates these three objectives. Moreover, there are other policy instruments that can be used to pursue these objectives. In the Commission’s view, these are not needed as explicit objectives. Consistent with the judgment that benefits arise from reducing the potential for conflicting objectives, these should be dropped.

The fourth listed objective, relating to rights of access to natural gas pipelines on conditions that are fair and reasonable for both service providers and users, is more a characteristic of the regime, rather than an objective. The detailed description and parameters of the regime relate directly to the provision of access on appropriate terms. It is not an appropriate explicit objective.

Similarly, the fifth listed objective, 'provides for the resolution of disputes', is really a characteristic of the Gas Access Regime rather than an objective. While a dispute resolution characteristic is needed, it is inappropriate to list it as an objective.

RECOMMENDATION 5.3

With the implementation of recommendation 5.1, the following objectives in the preamble to the existing legislation and the related objectives in the introduction to the Gas Code should be deleted:

(a) facilitates the development and operation of a national market for natural gas

(b) prevents abuse of market power

(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders

(d) provides for rights of access to natural gas pipelines on conditions that are fair and reasonable for the owners and operators of gas transmission and distribution pipelines and persons wishing to use the services of those pipelines

(e) provides for the resolution of disputes.

5.7 Guidance for access arrangements

The insertion of an overarching objects clause requires an assessment of the appropriateness of the guidance in the Gas Code for assessing access arrangements.

As noted in section 5.2 and listed in box 5.2, s.2.24 of the Gas Code lists seven factors a regulator must take into account when assessing a proposed access arrangement. As these factors currently provide further guidance to regulators on matters to be considered in approving an access arrangement, they need to be assessed for their continuing relevance — particularly in the circumstance of the proposed overarching objects clause. The conclusions of this assessment have implications for the guidance given to regulators in approving reference tariffs (s.8 of the Gas Code and particularly s.8.1), which are discussed in chapter 7.

The factors listed in s.2.24 of the Gas Code are considered below.

Interests of service provider and users

Sections 2.24(a) and (f) of the Gas Code state that a regulator must take into account when assessing a proposed access arrangement:

- the service provider's legitimate business interests and investment in the covered pipeline
- the interests of users and prospective users.

The CPA refers to the infrastructure owner's legitimate business interests and investment in the facility in relation to dispute resolution between a provider and a user.

Regarding users' interests, the CPA refers to users' rights to negotiate access and, in relation to dispute resolution, the interests of all persons holding contracts for use of the facility.

While ss2.24(a) and (f) recognise the interests of users and service providers, they do not give guidance about how to establish the right balance among the various interest groups. Since there is no mention of the criteria or basis on which the interests of service providers and users would be assessed, the objectives as expressed do not help the regulator.

There can sometimes be difficulties for regulators in resolving tensions between the interests of service providers and users. The Hilmer Committee noted:

> Neither the application of economic theory nor general notions of fairness provide a clear answer as to the appropriate access fee in all circumstances. Policy judgments are involved as to where to strike the balance between the owner's interest … and the user's interest … (Hilmer Committee 1993, p. 253)

The interplay between Epic Energy's legitimate business interests and investment in the Dampier–Bunbury pipeline, and the definition of efficient costs and hence prices, was a key issue in the Epic Energy court case. Epic Energy had an interest in recovering the purchase price of the pipeline, determined through a competitive tender process. Users had an interest in purchasing pipeline services in a way which covered efficient costs. This tension centred on the determination of efficient costs, which in turn depended on the capital value of the pipeline. Such a tension is exacerbated when other factors apart from economic efficiency considerations affect pricing decisions.

Epic Energy's business interests, and those of pipeline investors generally, are important because of the need to preserve incentives for investment. However, assessment of service providers' business interests should be based on economic efficiency considerations in order to be consistent with efficient pricing and incentives for efficient investment. Ergas argued:

> The Court's [Supreme Court of Western Australia's] decision is important given the emphasis it rightly places on the legitimate interests of facility owners. However, it seeks to import these interests as essentially going to wider, non-economic, considerations, rather than as being in fact core to a proper economic analysis of access charging. At the same time, the Court recognises the very wide discretion the [Gas] Code grants the regulator — a discretion which, it notes, could allow the regulator to set charges which did not even recover efficient costs. (Ergas 2003a, p. 15)

In the Commission's view, it is difficult to see why ss2.24(a) and (f) should be retained as explicit objectives. The overarching objects clause encapsulates the possible tension between the interests of service providers and users and seeks to resolve it in an efficiency context. In addition, the guidance for access arrangements discussed in chapter 7, particularly in relation to reference tariffs, would seem to cover these issues.

A number of pipeline service providers and their industry associations disagreed with the Commission's recommendation in the draft report to delete s.2.24(a) ('the service provider's legitimate business interests … '). A key argument offered was that the interests of pipeline owners were different in kind from those of the users of their services, and that property rights needed to be specifically recognised in the Gas Code.

The Energy Networks Association noted:

> … the interests of service providers under the Gas Access Regime are different in kind to other interests detailed in section 2.24 given substantial sunk capital investment in gas infrastructure and the need to provide adequate scope for ongoing investment … (sub. DR85, p. 13)

Envestra observed:

> … it is important to recognise property rights and the significant investment which a service provider may have made in the covered pipeline, as the courts recognised in the Western Australian Epic Energy case. (sub. DR82, p. 3)

The Australian Gas Light Company expanded on these views:

> The introduction of the Gas Access Regime resulted in a significant erosion of service provider's property rights. Service providers *lost* property rights to the future use of their assets with the introduction of the Gas Code, whereas users (existing and prospective) *gained* from mandated access rights without any qualification on the exercise of those rights except for the other provisions of section 2.24. Section 2.24(a) establishes a boundary to the extent of loss of rights of service providers. If section 2.24(a) were removed, users would still have their mandated rights of access,

> whereas specific protection for the rights of service providers will disappear. (sub. DR84, p. 4)

It would be expected that the property rights of pipeline owners would have been a particularly sensitive issue during the relatively lengthy transition period after the introduction of the Gas Access Regime. Appeal processes, which provide some protection for stakeholders, are especially important in the period following the imposition of regulation or following a change in regulatory arrangements.

The Supreme Court of Western Australia and the Australian Competition Tribunal referred to 'the service provider's legitimate business interests' in their consideration of appeals against decisions by regulators. The difference in the views of the Australian Competition Tribunal and the Australian Competition and Consumer Commission about the role and relative importance of this factor contributed to the Tribunal's recent decisions to overturn decisions of the Australian Competition and Consumer Commission in the Moomba–Adelaide pipeline and GasNet merits appeals (Australian Pipeline Industry Association, sub. DR100, pp. 12, 17).

The Commission considers that conflict in perceptions and evaluation of the appropriate role and impact of s.2.24(a) could be exacerbating uncertainty in decisions about access arrangements. The replacement of s.2.24(a) and (f) by the efficiency objective in the objects clause, together with the reforms to s.8 of the Gas Code (described in chapter 7), should provide a reasonable basis and better guidance for establishing the right balance between the interests of service providers and users, and might reduce the conflict of views.

Further, requirements to consider the interests of service providers and users open the way for importing an implicit objective in the regulatory process, based on notions of equity. Such an objective would be in addition to the explicit objective of efficiency being recommended in this inquiry, and would tend to retain an arbitrary element in the decision making process.

The Commission remains of the view that s.2.24(a) should be deleted.

Contractual obligations

Section 2.24(b) of the Gas Code states that a regulator must take into account 'firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline' when assessing a proposed access arrangement. The CPA also requires that the terms and conditions of access take into account contractual obligations.

As discussed in chapter 2, foundation contracts are important to the development of transmission pipelines. It is important that the provision of access to third parties does not impinge on the property rights of service providers and foundation customers. Further, impinging on these rights could have adverse implications for future investment in pipelines.

For these reasons, s.2.24(b) should be retained.

Safe and reliable operation of the covered pipeline

Section 2.24(c) of the Gas Code states that a regulator must take into account ‘the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline’ when assessing a proposed access arrangement.

Safety standards must be met irrespective of market conditions and access arrangements. Epic Energy expressed this idea:

> As the [Supreme Court of Western Australia] noted in the DBNGP [Dampier–Bunbury pipeline] decision, expenditure necessary for the safe and reliable operation of a pipeline would need to be taken into account whether or not it would have been made in a competitive market or according to theories of economic efficiency. (sub. 37, p. 50)

The AGA was concerned that reinvestment or investment must be sufficient to provide for ‘ongoing maintenance to existing distribution network assets to ensure the safe, reliable and efficient operation of the network (for example, through the monitoring and addressing of gas leakage levels and planned replacement of degraded assets)’ (sub. 13, p. 10).

On this issue, Epic Energy noted that it:

> … has long contended that it should be permitted to earn an appropriate return on its investment so as to enable it to make provision for the safe and reliable operation of the DBNGP [Dampier–Bunbury pipeline], including properly maintaining it. (sub. 37, p. 50)

It is usually regarded as good practice to separate the regulation of safety from that of economic issues. For example, the Department of Infrastructure noted that in Victoria:

> … arrangements were put in place to subject the private businesses to independent economic regulation by the now Essential Services Commission and safety regulation by the Office of Gas Safety. (sub. 71, p. 7)

However, clause 6(3) of the CPA requires that, for an access regime to conform to the principles, it should apply to services where:

> (a)(iii) the safe use of the facility by the person seeking access can be ensured at an economically feasible cost and, if there is a safety requirement, appropriate regulatory arrangements exist …

Safety issues are most likely to be of relevance at the time a third party user seeks access, rather than at the time a coverage decision is made. Further, one argument for an industry-specific access regime for gas is that there is potential for many third party access seekers. This suggests that it is important to retain the safety requirement as a factor to be considered in access arrangements. Therefore, the Commission recommends retention of s.2.24(c).

Compliance costs of meeting safety regulations need to be recovered from consumers and would be included in the costs to be met by the reference tariffs defined in recommendation 7.1. The requirement in this recommendation that only efficient costs should be recovered ought to protect users from funding excessive safety expenses.

The above proposal should also address any concerns users might have about a service provider using safety as a means as restricting access.

Economically efficient operation of the covered pipeline

Section 2.24(d) of the Gas Code states that a regulator must take into account ‘the economically efficient operation of the covered pipeline’ when assessing a proposed access arrangement. This is encapsulated by the proposed overarching objects clause which requires that the Gas Access Regime promotes economically efficient operation of pipelines. Section 2.24(d) should therefore be removed.

Public interest and any other matters

Under section 2.24(e), a regulator has to take into account ‘the public interest, including the public interest in having competition in markets’ in assessing proposed access arrangements. By considering the public interest, other factors, in addition to the economic costs and benefits directly affecting service providers and consumers, can potentially become important.

According to the Australian Competition and Consumer Commission and National Competition Council (ACCC and NCC 2002, p. 22), these other factors could include ‘environmental considerations, regional development and equity’. Other factors might be in conflict with competition policy and the principle of economic efficiency employed in the objects clause. Also, noneconomic objectives might not have measurable outcomes, which would adversely affect regulatory accountability.

The Victorian Department of Infrastructure noted that a Victorian Government objective was to ensure environmentally sustainable energy supplies for all Victorians at affordable prices. In the context of gas services for residents in regional and rural areas, the Department of Infrastructure stated:

> It is also important that the [Gas Access] Regime facilitate governments to support the extension of natural gas networks to towns that may not be commercially viable, but where a government considers that wider benefits may flow from such a project, and justify government assistance. (sub. 71, p. 3)

In its review of the national access regime, the Commission noted that income distribution objectives should be addressed, not by access regimes, but an instrument specifically targeting the objective:

> Indeed, explicit pursuit of broader distributional goals through an access regime could be inconsistent with the efficiency objective of part IIIA. For instance, if a regulator attempted on distributional grounds to set low access prices to assist particular groups of consumers, it could have adverse (short and long term) effects on efficiency. Yet, by using a more targeted instrument, such as budget-funded community service obligations, selected groups of consumers could be assisted without those deleterious impacts. (PC 2001c, p. 135)

The OECD study of competition objectives, referred to earlier, reported that 'there appears to be a shift away from the use of competition laws to promote broad public interest objectives' (OECD 2003, p. 9). It also noted, from a survey of member countries:

> … virtually no jurisdiction that has a competition law or policy which does not include public interest objectives has changed that law or policy to incorporate such objectives. (OECD 2003, p. 10)

The OECD concluded:

> The gradual shift away from use of competition laws in OECD countries to promote public interest objectives suggests that a consensus may be emerging that it is suboptimal, at least once a country has reached a certain level of development, to use competition law and policy to promote such goals. (OECD 2003, p. 10)

Under s.2.24(g) of the Gas Code, a regulator can take into account 'any other matters which it considers are relevant'. This gives the regulator far-reaching discretion in assessing proposed access arrangements, and opens up the possibility of lobbying by interest groups and political intervention.

Regulatory discretion in regard to weighing up possible tradeoffs among factors that are taken into account in assessing access arrangements might not be transparent. This would damage regulatory accountability.

Other instruments of government policy might be more appropriate for addressing specific public interest or other objectives (not related to economic efficiency). The best practice procedure is to ‘identify the relevant instruments which may be used to achieve the policy objectives’ and to evaluate the advantages and disadvantages of each instrument (PC 2001d, p. 108).

FINDING 5.3

The following elements of s.2.24 of the Gas Code are necessary to provide guidance for regulators when assessing access arrangements and should be retained:

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline

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

RECOMMENDATION 5.4

The following elements of s.2.24 of the Gas Code do not provide necessary guidance to regulators when assessing access arrangements and should be deleted:

(a) the Service Provider’s legitimate business interests and investment in 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.

5.8 Guiding principles for arbitrating a dispute

As discussed earlier in the chapter, s.6.15 of the Gas Code lists factors to be taken into account by an arbitrator of a dispute between a service provider and a user about the terms and conditions of an access arrangement. These factors are quite similar to the factors in s.2.24 of the Gas Code and match even more closely the dispute resolution principles in clause 6(4)(i) of the CPA.

Consistency of guidance to arbitrators and regulators

Guidance for the regulator of access arrangements in s.2.24 of the Gas Code and guidance for the arbitrator of a dispute between a service provider and an access seeker in s.6.15 should be consistent. Adjustments should be made to s.6.15 that are similar to those recommended above for s.2.24 in order to provide consistent directions to arbitrators and regulators. Each of these are discussed below.

Factors (a) and (d) in s.6.15, relating to the interests of service providers and users, correspond to factors (a) and (f) in s.2.24. The Commission recommends that they be deleted from s.6.15 for the reasons given above in the discussion of s.2.24.

Factors (b) and (c) of s.6.15 relate to the price of access. However, according to s.6.18(e), the arbitrator must not require the service provider or user to accept a *reference service* at a tariff other than the reference tariff which has already been approved by the regulator, and therefore arbitrators do not need the additional guidance in (b) and (c).

Factors (e) and (f) of s.6.15, referring (respectively) to firm and binding contractual obligations and operational and technical requirements for safe and reliable operation, replicate (b) and (c) of s.2.24 and should be retained for the reasons discussed earlier.

Factors (g) and (h) of s.6.15, relating (respectively) to economically efficient operation of the pipeline and benefit to the public from having competitive markets, correspond to factors (d) and (e) of s.2.24, and are not needed for reasons discussed earlier.

FINDING 5.4

The following elements of s.6.15 of the Gas Code are necessary to provide guidance for arbitrators when arbitrating disputes over access arrangements and should be retained:

(e) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline

(f) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline.

RECOMMENDATION 5.5

The following elements of s.6.15 of the Gas Code do not provide necessary guidance to arbitrators when arbitrating disputes over access arrangements and should be deleted:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline

(b) the costs to the Service Provider of providing access, including any costs of extending the Covered Pipeline, but not costs associated with losses arising from increased competition in upstream or downstream markets

(c) the economic value to the Service Provider of any additional investment that the Prospective User or the Service Provider has agreed to undertake

(d) the interests of all Users

(g) the economically efficient operation of the Covered Pipeline

(h) the benefit to the public from having competitive markets.

The above deletions would have consequences for the situation where there is a dispute about the price of access to a *non-reference service*. In this circumstance, it would be appropriate for the arbitrator to be guided by the pricing principles recommended in chapter 7 (recommendation 7.1). This guidance should be inserted into the list of factors for the arbitrator to take into account in s.6.15.

RECOMMENDATION 5.6

An additional factor should be added to s.6.15 of the Gas Code, as follows:

> ***In the event of a dispute about the price of access to a non-reference service, the arbitrator should be guided by the pricing principles in s.8.1 of the Gas Code (as revised by recommendation 7.1).***

Implications for certification

The changes to s.6.15 (resulting from the changes to s.2.24) of the Gas Code could have implications for the certification of the revised form of reference tariff regulation proposed by the Commission.

This issue was raised by a number of industry participants who cast doubt on whether the Gas Access Regime would be certified as effective if the deletions were implemented. The comments were mostly in relation to the proposed deletion of s.2.24(a) (‘the service provider’s legitimate business interests …’).

The Energy Networks Association suggested:

> … the removal of a requirement to consider the ‘legitimate business interests’ of service providers appears to be inconsistent with the minimum requirements necessary for a regime to be certified as effective established by the Competition Principles Agreement 1995. (sub. DR85, p. 13)

The Australian Gas Light Company noted that s.2.24(a):

> … reappears in section 6.15(a), providing guidance for arbitrators in access disputes under the Gas Code (and in fact is one of the requirements for an ‘effective’ access regime specified under clause 6(4) of the Competition Principles Agreement). … There appears to be a serious loss of balance in removing section 2.24(a) from assessment of an access arrangement but retaining it (appropriately) in section 6.15(a). (sub. DR84, p. 5)

Epic Energy argued for retention of all of s.2.24 to ensure certification and for other reasons (sub. DR109, pp. 5–8, 21).

In its review of the national access regime, the Commission recommended (recommendation 9.2) that the parties to the CPA negotiate changes to clause 6 of the agreement to align it with the modified part IIIA, having regard to finding 9.2. This would include revisions to clause 6(4)(i) of the CPA dealing with dispute resolution under cost-based price regulation. The Australian Government responded by stating that it supported the Commission’s recommendation (Costello 2004, p. 11).

The monitoring form of regulation described in chapter 8 also raises issues for certification of the Gas Access Regime. Certification and the implications for the CPA are considered in the context of both forms of regulation (monitoring and access arrangements with reference tariffs) in chapter 8.

6 Coverage issues

The National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) only applies to natural gas transmission pipelines and distribution networks that are covered under the regime (via the processes and requirements outlined in chapter 3). The service provider of a covered pipeline is required to implement an access arrangement approved by the regulator. In this chapter, coverage issues, including the criteria used to determine whether pipelines should be covered, are discussed. The importance of coverage and the coverage criteria is discussed in section 6.1. The Productivity Commission's approach is outlined in section 6.2. Inquiry participants' initial views (prior to the draft report) on coverage issues and on specific coverage criteria are highlighted in sections 6.3 and 6.4 respectively. The draft report proposals and inquiry participants' comments on those proposals are summarised in sections 6.5 and 6.6 respectively. The Commission's assessment and recommendations are in section 6.7.

6.1 Why coverage and the coverage criteria are important

Under the Gas Access Regime, a pipeline can become covered in four ways (chapter 3). The coverage process and application of the coverage criteria are relevant when someone applies to the National Competition Council (NCC) for coverage or revocation of coverage.

The NCC makes a recommendation and the relevant Minister makes a decision in relation to two options:

- that a pipeline be covered (in whole or in part) or
- that a pipeline not be covered.

When a pipeline is covered, the pipeline owner or operator (service provider) must fulfil all of the requirements of the regime (such as implementing an access arrangement with regulator approved reference tariffs, and ring fencing arrangements — chapters 7 and 10 respectively).

Regulation to create legal rights to negotiate access and to set the terms of that access can involve costs as well as benefits. Further, the magnitude of the costs and benefits is uncertain, varying with the market circumstances facing each pipeline (chapters 2 and 4). It is important to limit the application of the regime to those circumstances in which it is likely that the benefits of regulation outweigh the costs. The coverage criteria play a fundamental role in ensuring the regime is applied only in circumstances where it will achieve this objective.

FINDING 6.1

It is important that the coverage process and criteria are designed so that regulatory intervention occurs only in those circumstances in which it is likely the benefits of regulation outweigh its costs.

6.2 The Commission's approach

After the release of the draft report, two developments have had a significant bearing on the Commission's deliberations with regard to assessment of the coverage criteria.

- On 20 February 2004 the Australian Government released its final response to the Commission's review of the national access regime (part IIIA of the *Trade Practices Act 1974* [TPA]). The response announced changes to one of the declaration criteria under the national access regime, which has important implications (including through certification) for the coverage criteria for the Gas Access Regime.
- Participants provided feedback on the Commission's proposals set out in the draft report.

As a result of these developments, the Commission has revised its recommendations (in relation to coverage issues) from those set out in the draft report. This chapter is structured chronologically, with the initial views of inquiry participants presented first, followed by a summary of the Commission's draft report proposals, participants' responses to the draft report, and the Commission's recommendations.

6.3 Inquiry participants' initial views on coverage issues

The current four coverage criteria are presented in box 6.1. A pipeline must meet all of these criteria to be covered. They are similar to those in the existing national access regime.

Inquiry participants made general comments regarding the coverage criteria, their applicability to different types of pipeline (transmission versus distribution, greenfields versus existing) and transitional issues arising from the implementation of the Gas Access Regime.

Box 6.1 **Existing coverage criteria**

Section 1.9 of the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code) states:

> Subject to sections 1.4(a) and 1.10, the NCC [National Competition Council] must recommend that the Pipeline be covered (either to the extent described, or to a greater or lesser extent than that described, in the application) if the NCC is satisfied of all of the following matters, and cannot recommend the Pipeline be covered, to any extent, if the NCC is not satisfied of one or more of the following matters:
>
> (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;
>
> (b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline;
>
> (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
>
> (d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

Views on the coverage criteria differed across various groups. Gas users generally supported the current coverage criteria, for example, the Energy Markets Reform Forum (sub. 30, p. 17), WMC Resources (sub. 43, p. 43) and BHP Billiton (sub. 62, p. 2). The NCC considered:

> … the current coverage test is appropriate. It is consistent with the principle endorsed by the Government [in its interim response to the part IIIA review], and is consistent with the principles established by the Competition Principles Agreement and with the declaration test contained in part IIIA of the TPA. (sub. 57, p. 11)

In contrast, transmission pipeline and distribution network owners had concerns with the current criteria. The Australian Gas Light Company (AGL) noted:

> … the current coverage test and its application fail to meet the objective of only regulating pipelines where the benefits of increased competition clearly outweigh the costs to the community. (sub. 32, p. 24)

The Australian Gas Association (AGA) considered there has been inappropriate initial coverage of the regime and inappropriate coverage of competing pipelines and greenfield network and pipeline developments (sub. 13, pp. 73–4, 79). The Australian Pipeline Industry Association (APIA) stated that ‘errors in the design of the Gas Access Regime and in its application have made the system unworkable for Australia's gas transmission sector' (trans., p. 367). In part, it recommended a 'strengthened coverage test to ensure that only pipelines that misuse market power are covered' (sub. 44, p. 3).

Transmission pipelines and distribution networks

Some inquiry participants highlighted the differences between transmission pipelines and distribution networks. The AGA, whose membership is drawn largely from gas distribution businesses, argued that the existing coverage test is flexible enough to deal with both distribution networks and transmission pipelines:

> … because the two principal legs upon which many pipelines and networks have gained revocation under the regime is the market power test and also the costs and benefits test, and there have been a substantial number of gas distribution networks, principally serving small regional areas, which have applied to the National Competition Council; the National Competition Council has recommended revocation, and that has gone forward, so we believe the test — a slightly amended test — is wide enough to encompass both classes of assets. (trans., pp. 18–19)

On the other hand, the Northern Territory Treasury considered there might be a case for an alternative approach for distribution networks, due to the compliance difficulty (sub. 41, p. 5). Goldfields Gas Transmission considered that the differences between transmission pipelines and distribution networks were so fundamental as to warrant separate treatment:

> Distribution systems are likely to be more stable and longer lived. Transmission lines, on the other hand, have very different characteristics:
>
> - they are the link between the depleting gas resource and the market
> - the economics of transmission are extremely sensitive to pipeline size and throughput …
> - they are often constructed in remote and inhospitable places
> - their viability (or their profitability) can be dependent on a small number of large industrial loads
> - capacity can be in danger of being stranded on a long term basis. (sub. 16, p. 3)

AGL (sub. 32, pp. 21–2) and Allgas Energy (sub. 25, p. 12) acknowledged the different challenges faced by transmission pipelines and distribution networks but neither perceived the need for separate access regimes for transmission pipelines and distribution networks.

Greenfield developments

As discussed in chapter 4, a number of inquiry participants considered that the coverage (or threat of coverage) of greenfield developments has reduced the incentive to invest in pipelines. The AGA commented:

> The current provisions of the Gas Access Regime do not adequately facilitate efficient investment in greenfield projects. There is a need for a separate greenfield mechanism to ensure that the future Gas Access Regime does not have the effect of deterring efficient investment. Greenfield projects have a range of specific features which make the application of the existing access regime inappropriate. (sub. 13, p. 59)

In June 2002, in response to concerns about the possible chilling effect of the Gas Access Regime on greenfield investments, the Australian Competition and Consumer Commission (ACCC) (2002a) published a draft guideline that seeks to address such concerns. This issue and the guideline are discussed in chapter 9.

Transitional issues

Some inquiry participants commented on the costs associated with pipelines that were listed in schedule A of the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code) and thus automatically covered (chapter 3). Service providers were required to seek revocation if they considered the pipeline did not meet the coverage criteria.

APIA noted that 'at no point was a transparent assessment made of whether the pipelines in schedule A satisfied the relevant coverage criteria' (sub. 44, p. 27). It observed that 17 pipelines and distribution systems have subsequently had to invest significant resources to have their coverage status revoked to avoid unnecessary regulatory intervention. In the case of the NT Gas City Gate–Berrimah pipeline, the costs of the successful revocation application represented '23 per cent of annual revenue from the pipeline' (sub. 44, p. 27).

AGL also noted:

> There are likely to be pipelines covered at present where it is demonstrable that coverage is not beneficial to the community. … The cost of the revocation process, combined with the issues around the current test are likely to mean pipeline owners will not seek revocation and they will remain covered, resulting in unnecessary compliance costs. Strengthening the coverage test should provide an opportunity for the removal of inefficient regulation, ultimately providing a better result for the community. (sub. 32, p. 25)

Process for seeking coverage

Inquiry participants raised concerns about the provision allowing any person to make a coverage application to the NCC. Origin Energy (sub. 52, p. 5), Envestra (sub. 22, p. 6) and AGL considered that it was inappropriate that regulators can seek coverage, with the latter noting that 'that no one body should have powers to determine what rules should apply to particular services and then to administer the rules in respect of those services' and 'allowing one body to have this dual role is of concern' (AGL, sub. 32, p. 26).

Inquiry participants also raised concerns that coverage can be considered when there has been no attempt to negotiate access. Duke Energy International noted:

> … coverage application should only be able to be lodged on a pipeline where it can be demonstrated that the facility owner has unreasonably denied access to an access seeker. At present, coverage can be sought even when an attempt to negotiate access has not been made. Although section 1.4 of the [Gas] Code enables vexatious or trivial coverage applications to be dismissed outright, the potential still exists for access seekers attempting to gain a competitive advantage to submit an application on purely strategic grounds. This results in significant time and costs for not only the asset owner, but the regulator and other industry participants. (sub. 21, p. 15)

APIA considered that 'limiting applications to situations in which access had been sought and not provided, or unreasonably delayed, would give greater weight to the commercial processes that should be central to the access mechanism' (sub. 44, p. 66).

Forum shopping

A service provider has scope to submit an undertaking under part IIIA of the TPA when coverage under the Gas Code has not been determined. The Government of South Australia noted:

> … there should only be one pathway for access to gas pipelines. As the [Gas Access] Regime was envisaged as the primary mechanism for regulating gas pipeline access in Australia, [the Government of South Australia] suggests that this be clearly established by nullifying other paths, such as an access undertaking through part IIIA, for seeking access to gas pipelines. (sub. 58, p. 15)

Greg Harvey, the Independent Chair of the National Gas Pipelines Advisory Committee, considered that the possibility of forum shopping was 'more perceived that real', but 'the perceptions ought to be removed, if they can be, and certainty and clarity will only assist the better operating of the [Gas] Code' (trans., p. 98).

6.4 Inquiry participants' initial views on specific coverage criteria

Inquiry participants also provided comments on the four specific coverage criteria of the Gas Code (box 6.1). Participants' comments tended to focus on the 'promotion of competition' test (criterion [a]), the 'uneconomic to develop another pipeline' test (criterion [b]), and the 'not be contrary to the public interest' test (criterion [d]). Little comment was made on the 'access provided without undue risk to human health and safety' test (criterion [c]). Some inquiry participants suggested a new criterion based on the relative economic significance of pipelines.

'Promotion of competition' test — criterion (a)

(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 (a) relates to whether coverage of the pipeline would promote competition upstream or downstream from the pipeline. It originated in the Hilmer Committee (1993) recommendations. Particularly, the recommendation that a right of access be created only where the owner agrees or the relevant Minister is satisfied that 'access to the facility in question is essential to permit effective competition in a downstream or upstream activity' (Hilmer Committee 1993, p. 266).

The NCC considered that market power is central to criterion (a):

> The notion of competition is central to criterion (a) and to Australian trade practices law.
>
> … The key feature of effective competition is that no one seller (or group of sellers) or buyer (or group of buyers) has sustained and substantial market power.
>
> The Council considers that it is fundamental to a consideration of criterion (a) to identify the incentives and ability of a pipeline operator to exploit its market power in the transmission market in a dependent market.
>
> In the Duke [Eastern Gas Pipeline] decision, the [Australian Competition Tribunal] found that the ability to exercise market power in a dependent market is a key factor in determining whether coverage would promote competition. (sub. 57, p. 34)

The NCC's approach for assessing this criterion is set out in box 6.2.

The Minister's recent decision on revocation of coverage of parts of the Moomba–Sydney pipeline considered the approach adopted by the NCC. The

Minister's decision adopted the broad framework developed by the NCC, but considered some reassessment and refinement is required. In particular he noted:

> Building on the framework developed by the [National Competition] Council, certain minimum requirements are necessary both to limit the ability of gas transmission pipeline owners and operators to exert market power in dependent markets and to constrain the ability of either upstream or downstream participants to exercise power in that market by the way they contract for these pipeline services, namely that:
>
> (a) at least three independent (either competitive or regulated) pipelines can offer, or are capable of offering, transmission services in each dependent market
>
> (b) competitive market factors, as identified by the [Australian Competition] Tribunal, either should be or are likely to be sufficiently evident in each dependent market, including the absence of price collusion or coordination
>
> (c) provision of gas pipeline services in an upstream or downstream market should not be qualified to a significant degree by vertical integration or horizontal consolidation
>
> (d) consideration may be given to individual circumstances on a case-by-case basis, such as the specific requirements for regional areas. (Macfarlane 2003a, para. 110)

Box 6.2 **The National Competition Council's approach to assessing the promotion of competition criterion (criterion [a])**

The NCC set out its process for considering criterion (a) in its draft recommendation on the application for revocation of coverage of the Goldfields Gas Pipeline.

> In assessing whether criterion (a) is satisfied, the Council must:
>
> (a) define the relevant market(s) in which competition may be promoted and verify that this market or these markets are separate from the market for the service to which access is sought
>
> (b) determine whether access (or increased access) facilitated by coverage would promote a more competitive environment in the additional market(s), which requires an assessment of:
>
> (a) whether the incumbent has the ability and incentive to exercise market power to adversely affect competition in the dependent market(s)
>
> (b) whether the structure of the dependent market(s) is such that coverage would, by constraining the exercise of market power by the service provider to adversely affect competition in the dependent market(s), promote competition.

Source: NCC 2003, pp. 36–7.

Some inquiry participants considered whether the Gas Code coverage criteria should be amended to reflect the Productivity Commission's recommendation to narrow the declaration criteria for the national access regime (PC 2001c, p. xxiii).

Goldfields Gas Transmission considered:

> In its review of part IIIA, the Productivity Commission has recommended that 'access (or increased access) should promote a substantial increase in competition'. The Government, in its response to the Productivity Commission recommendations, has expressed a preference for the word 'material' in place of 'substantial'. [Goldfields Gas Transmission] believes that in the context envisaged, 'substantial' is to be preferred over 'material'. (sub. 16, p. 10)

Similarly, other inquiry participants — including AGL, Enertrade, Duke Energy International, the AGA, Envestra and the Government of Queensland — supported amending criterion (a) to read a 'substantial' increase in competition. However, the Energy Markets Reform Forum noted:

> On the issue of the term 'substantial' versus 'material' in terms of section 44G(2)(a) [of the TPA], the [Energy Markets Reform Forum] supports the Commonwealth Government's preference for 'material'. (sub. 30, p. 17)

Some inquiry participants were uncertain about the significance of the distinction between 'substantial' and 'material', including the AGA (trans., p. 20), APIA (sub. 44, pp. 54–5) and Origin Energy (sub. 52, pp. 5–6).

BHP Billiton, in noting that a number of submissions suggested amending criterion (a), concluded:

> In our view, the suggested changes, primarily being to change the threshold for the level of competition created in the related market(s) seek to inappropriately alter the balance of the entire coverage test. Moreover, the focus on the threshold for the level of competition created in the related market(s) also appears to reflect a misunderstanding of the dual role of the Gas Code. (sub. 62, p. 1)

Professor Littlechild suggested expanding the promotion of competition test to require the NCC to assess whether promotion of competition would occur without coverage:

> These conditions seem to assume that regulation can only be beneficial. But this is not the case: as noted, regulation can severely reduce incentives to enter and compete. Accordingly, the conditions might be expanded to require the NCC to be satisfied that regulatory coverage is actually needed, in the sense that competition in other markets would not be promoted in its absence. The conditions might also require the NCC to be satisfied that regulatory coverage would not discourage the development and operation of further pipelines.
>
> More generally, any proposal to introduce or extend regulatory coverage should have to establish the absence of disadvantages as well as the existence of potential advantages. (sub. 24, p. 3)

There were few concerns with the 'whether or not in Australia' rider in criterion (a). Goldfields Gas Transmission considered that it 'is redundant' (sub. 16, p. 10).

‘Uneconomic to develop another pipeline’ test — criterion (b)

(b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline

Criterion (b) is generally considered to relate to the existence of natural monopoly. An issue with the criterion relates to the definition of the services provided by means of the pipeline. The NCC uses a ‘point to point’ service definition — that is, the service is transportation of natural gas from the origin to the destination (for example, from Moomba to Sydney) and offtake points along the pipeline. The NCC noted that the Australian Competition Tribunal established this definition in its decision on coverage of the Eastern Gas Pipeline (NCC, sub. 57, p. 23).

Other inquiry participants argued that the definition of services should be broader to include the delivery of (1) services from alternative sources to the same market and (2) competing sources of energy into the same market. Goldfields Gas Transmission considered that criterion (b) should be broadened to consider competing energy forms (sub. 16, pp. 19–20). Duke Energy International considered that criterion (b) precludes considering the feasibility of developing pipelines from other sources of gas or close substitutes of gas (such as electricity) (sub. 21, p. 18).

The Minister’s recent decision on revocation of coverage of parts of the Moomba–Sydney pipeline considered the NCC’s methodology:

> While I accept much of the [National Competition] Council’s methodology where it relates to the provision of a single point-to-point transmission service, I am not satisfied that the Council has established an adequate framework for assessing criterion (b), particularly as it relates to the circumstances of the [Moomba–Sydney pipeline] mainline. This conclusion reflects the rapidly expanding structure of natural gas pipeline networks, compared with their historical configuration when the [Gas] Code was established in 1998, and the case law available for this criterion. (Macfarlane 2003a, para. 8)

Some inquiry participants (such as APIA, sub. 44, p. 59) noted, as a consequence of the NCC’s approach, that gas pipelines usually satisfy this criterion. While acknowledging this issue, the NCC considered that criterion (b) should remain in its current form:

> Notwithstanding … [the possibility that technological developments may result in the development of other means to transport natural gas in the future], the [National Competition] Council considers that criterion (b) in the Gas Code should remain in its current form. The fact that the coverage criteria might readily be satisfied in the case of a gas transmission pipeline should not be regarded as an unlikely or unintended legislative outcome. (sub. 57, p. 24)

The NCC also stated:

> The [National Competition] Council supports the approach to the definition of 'Service provided by means of the pipeline' established by the decision of the [Australian Competition Tribunal] in Duke [Eastern Gas Pipeline]. Criterion (b) is intended to identify services provided by means of facilities which exhibit natural monopoly characteristics. By contrast, criterion (a) considers the upstream and downstream markets for those services. The Council submits that it is important to maintain this distinction, to ensure consistency with the principles of access regulation articulated in the Competition Principles Agreement. (sub. 57, p. 26)

'Access provided without undue risk to health or safety' test — criterion (c)

(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

Criterion (c) ensures access to a service does not compromise human health or safety. The NCC's guide to part IIIA of the TPA (which has a similar requirement for declaration) notes that some facilities might require a degree of spare capacity to provide appropriate safety margins and that provision of access must not compromise safe scheduling (NCC 2002c, p. 19).

In relation to assessing whether criterion (c) is met, the NCC also noted:

> The existence of relevant safety regulations may satisfy [the health and safety criterion] where these regulations deal appropriately with any safety issues arising from access to the service provided by the facility.
>
> … a number of applications seeking revocation … did not raise safety concerns to support revocation. This is likely to be at least partly attributable to the safety regulations implemented by relevant governments. New South Wales, South Australia, Queensland and the ACT have passed regulations dealing with the safe operation of gas pipelines. (NCC 2002c, p. 103)

The safety criterion might also be satisfied where the terms and conditions of access can address any safety concerns (NCC 2002c, p. 103).

Inquiry participants raised few issues about criterion (c). Goldfields Gas Transmission considered its inclusion to be unnecessary, as 'these matters are quite adequately addressed in relevant laws and regulations and it should not be the function of an access regime to overlay these in any way' (sub. 16, p. 12).

The Western Australian Government considered that 'it is fundamental that provision of third party access should maintain human health and safety hence section 1.9(c) is appropriate' (sub. 70, p. 9). The NCC also considered it should be retained to maintain consistency with part IIIA (sub. 57, p. 45).

'Not be contrary to the public interest' test — criterion (d)

> *(d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest*

A broad range of matters could be considered under criterion (d). Clause 1(3) of the Competition Principles Agreement (CPA) contains a nonexhaustive list, including ecologically sustainable development, social welfare and equity, occupational health and safety, economic and regional development, the interests of consumers, the competitiveness of Australian businesses and the efficient allocation of resources (NCC 1998, pp. 14–15).

The World Bank and OECD noted difficulties in defining 'public interest':

> Public interest is an elusive and amorphous concept. In many cases public interest can be widely divided, and what might be considered clearly in the public interest by one party may be seen as less important by another. (World Bank and OECD 1999, p. 5)

The NCC stated that it adopts a broad view of the matters that might raise public interest considerations, including 'the overall costs of regulation, and any effects that regulated access might have on the environment, regional development, and equity' (sub. 57, p. 47). Nonetheless, in its guide to part IIIA of the TPA, the NCC noted that 'a key public interest consideration is the net impact … on economic efficiency'(NCC 2002c, p. 20). It made the same point in its submission to the review of the national access regime, suggesting that the test of not being contrary to the public interest provides the primary vehicle for assessing the net impact on efficiency (NCC 2001, pp. 84–5).

The NCC noted that the Australian Competition Tribunal decision on coverage of the Duke Energy International's Eastern Gas Pipeline clarified the interpretation of criterion (d). The decision noted:

> … criterion (d) does not constitute an additional positive requirement which can be used to call into question the result obtained by the application of paras (a), (b) and (c) of the [coverage] criteria. Criterion (d) accepts the results derived from the application of paras (a), (b) and (c), but enquires whether there are any other matters which lead to the conclusion that coverage would be contrary to the public interest. (Australian Competition Tribunal 2001, para. 145, cited in NCC, sub. 57, p. 46)

The current drafting of this criterion might result in coverage where the effect on economic efficiency is only a minor improvement, no improvement at all, or negative (where it is outweighed by benefits from nonefficiency issues). The NCC noted:

> The criterion's use of the double negative — requiring satisfaction that access 'would not be contrary to the public interest' — indicates that it does not constitute an additional positive requirement for satisfaction that access would be in the public interest. Rather, the [National Competition] Council must be satisfied that the overall costs of coverage do not outweigh the benefits of coverage. (NCC 2003b, p. 133)

More explicitly, regarding interpretation of criterion (d), the NCC considered:

> … [the] proper structure to be imposed upon clause (d) is that:
>
> (a) if the public benefits exceed the public detriments, then criterion (d) is met
>
> (b) if the public benefits and public detriments are evenly balanced, then criterion (d) is met
>
> (c) if the public detriment exceeds the public benefit, then criterion (d) is not met. (sub. 57, p. 46)

Goldfields Gas Transmission commented that this criterion is the 'only criterion that addresses costs and benefits' and considered that it should be retained (trans., p. 75).

Whether to add a new criterion for the size or economic significance of pipelines

None of the coverage criteria explicitly relate to the size or significance of pipelines in coverage decisions. In contrast, the declaration criteria in part IIIA of the TPA require the facility to be of national significance, which the Commission interpreted as to 'ensure that only facilities with a significant role in the economy fall within the scope of part IIIA' (PC 2001c, p. 168).

Some inquiry participants considered that the absence of a 'national significance test' in the coverage criteria is a deficiency, for example Goldfields Gas Transmission (sub. 16, pp. 7, 10), Chamber of Commerce and Industry of WA (sub. 39, p. 5). The AGA recognised that the physical scale of network or pipeline assets might influence the cost-effectiveness of various forms of access pricing regulation (sub. 13, p. 41).

6.5 Draft report proposals

In the draft report, the Commission proposed changes to the coverage criteria (to raise the threshold for coverage), a new framework for coverage decisions that would also include a decision on the form of regulation to apply (an access arrangement with reference tariffs or a light-handed option) and other changes, including reducing the opportunity for forum shopping.

Modifying the coverage criteria

The Commission considered that the coverage test for the Gas Access Regime, given the regime's heavy-handed characteristics (cost-based price regulation), sets too low a threshold for regulation. The Commission proposed raising the threshold to ensure coverage is likely to result in a significant improvement to economic efficiency. That is, the framework must consider the benefits of coverage (improvement in economic efficiency from granting third party access) and the costs of coverage (the cost of regulation, particularly through its effect on the efficient provision of pipelines). Given the potential for regulatory error in applying price regulation, these changes are important.

In particular, the Commission proposed:

- raising the hurdle for coverage under criterion (a) such that access (or increased access) would be likely to have the effect of increasing competition to a material degree. This wording reflected advice from the Australian Government Solicitor who considered this threshold was higher than the current requirement to 'promote competition'
- removing the 'access provided without undue risk to human health and safety' criterion
- adding a new efficiency criterion — namely, that coverage of the pipeline is likely to improve economic efficiency significantly (box 6.3).

To help the relevant regulator assess the increase in competition that would result from access, the Commission recommended including in the Gas Access Regime a list of factors to be taken into account. This is similar to the approach used in the telecommunication access regime and for assessing mergers in the TPA.

Form of regulation

In the draft report, the Commission proposed a light-handed option for regulation (involving monitoring) be available for covered pipelines to provide a way of keeping some covered pipelines out of access arrangements with reference tariffs where the costs of such regulation are likely to exceed the benefits, but where it is not appropriate to reject coverage. It proposed that the NCC be required to make two recommendations in relation to coverage:

- whether the pipeline should be covered
- if the pipeline should be covered, which form of regulation should be applied: (1) an access arrangement with reference tariffs or (2) a monitoring option.

Box 6.3 **Draft report — the Commission's proposed coverage criteria in s.1.9 of the Gas Code**

In the draft report, the Commission proposed replacing s.1.9 of the Gas Code with the following coverage criteria:

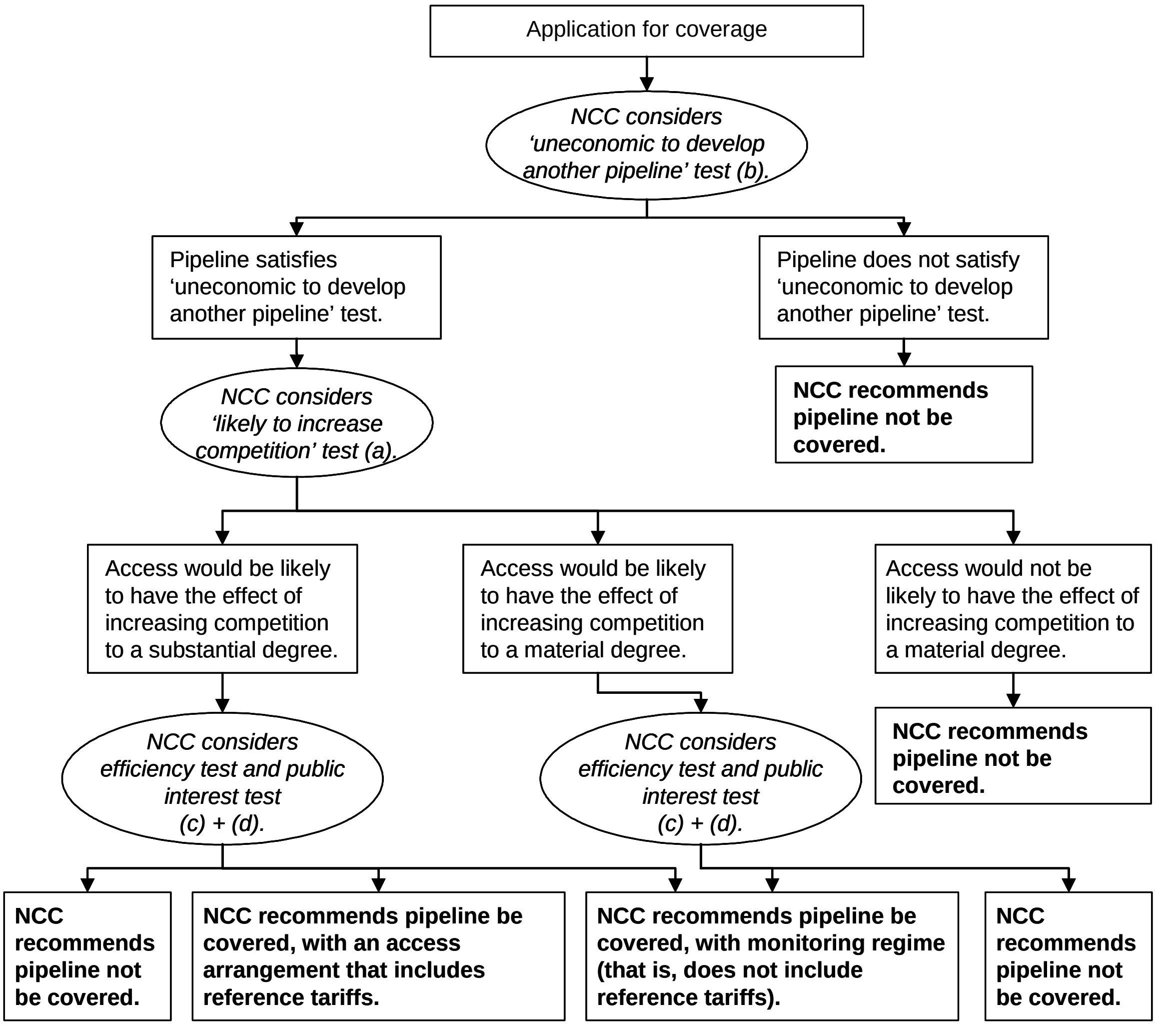
> Subject to sections 1.4(a) and 1.10, the NCC must recommend that the Pipeline be Covered (either to the extent described, or to a greater or lesser extent than that described, in the application) if the NCC is satisfied of all of the following matters, and cannot recommend the Pipeline be Covered, to any extent, if the NCC is not satisfied of one or more of the following matters:
>
> (a) that access (or increased access) to Services provided by means of the Pipeline would be likely to have the effect of increasing competition to a material degree in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline;
>
> (b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline;
>
> (c) that coverage of the Pipeline is likely to improve economic efficiency significantly; and
>
> (d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

The Commission considered that the potential net benefits from regulation should dictate the form of regulation. It proposed that the extent to which access would be likely to increase competition (proposed revised criterion [a]) and improve economic efficiency (proposed new efficiency criterion) should determine the form of regulation to apply. In particular, the monitoring option should be applied if one of the following applies:

- if access (or increased access) would be likely to have the effect of increasing competition to a material, but not a substantial, degree (and if the other tests are met)
- if access (or increased access) would be likely to have the effect of increasing competition to a substantial degree, but applying the monitoring option (with its lower costs) would improve economic efficiency more than would an access arrangement with reference tariffs (and if the other tests are met).

The Commission proposed that the current regulatory approach (access arrangements with reference tariffs) should be applied only if access (or increased access) would be likely to have the effect of increasing competition to a *substantial* degree, and if such regulation would improve economic efficiency more than would the monitoring option (and if the other tests are met). The then proposed process is illustrated in figure 6.1.

Figure 6.1 **Draft report — Commission's proposed framework for coverage decisions**



Other issues

In relation to forum shopping, in the draft report the Commission reiterated its conclusion and recommendation from its review of the national access regime that a part IIIA undertaking should not be accepted where coverage under the Gas Code has yet to be resolved.

The Commission also considered there might be merit in limiting coverage applications for uncovered pipelines to access seekers that demonstrate they have undertaken 'best endeavours' in commercial negotiations that failed. This was designed to reduce the potential for strategic behaviour by access seekers.

6.6 Inquiry participants' views on the draft report proposals

Inquiry participants provided feedback to the Commission on its draft report proposals in submissions and public hearings. Their feedback focused primarily on the practicality of the Commission's proposal for the coverage criteria (particularly two different thresholds in the 'likely to increase competition' test) to be used to decide on the form of regulation.

Transmission pipelines and distribution networks

There was broad support of the Commission's conclusion in the draft report that different coverage criteria for transmission pipelines and distribution networks were not warranted. The Energy Networks Association (which has replaced the AGA) noted:

> We've always argued that there should be a single regime, in terms of the nature of the businesses and what the regime seeks to address. There isn't any reason to have separate regimes at all. In that regard I think the report is setting down the right path. (trans., p. 584)

The NCC stated:

> In considering applications for coverage and revocation of distribution and transmission pipelines, we have never experienced difficulty in applying the criteria to those different sorts of infrastructure in a way you would think that they were not appropriate. The [National Competition] Council does support the single framework applying to both transmission and distribution. (trans., p. 661)

The Energy Markets Reform Forum commented:

> … we recognise that there are differences between transmission and distribution pipelines, but we also think that we should only stay with one single access regime if only for consistency's sake. Once you have two separate regimes or have different treatments, if you like, or different provisions for different pipelines, you run into problems of uniformity, interpretation and you run into problems of consistency. (trans., p. 756)

Modifying the coverage criteria

Inquiry participants' feedback on the Commission's proposals focused on the change to the 'promotion of competition' test (criterion [a]) and the practicality of including two thresholds within this criterion — 'material' and 'substantial' for determining the form of regulation for covered pipelines. (The Commission's coverage criteria proposed in the draft report are presented in box 6.3.)

‘Promotion of competition’ test — criterion (a)

Many inquiry participants were concerned with the Commission’s proposal to include a two-tiered threshold in criterion (a) — based around the differences between ‘material’ and ‘substantial’ — particularly the practicality of distinguishing between the two thresholds. Worsley Alumina stated that it:

> … is concerned with the proposed introduction of ‘substantial’ and ‘material’ as qualifying terms within the [Gas] Code. Worsley considers that such terms are highly discretionary, difficult to use and may serve to introduce further unnecessary potential for conflict and dispute between parties under the Code. (sub. DR110, p. 13)

APIA considered:

> In practice, the absence of the difference between the tests is exacerbated by the practical reality that both tests are applied in an essentially abstract environment with a threshold of ‘likely’. In a coverage application, the NCC and then the Minister (and ultimately the [Australian Competition] Tribunal) would be asked to consider the difference between two virtually indistinguishable tests in a hypothetical case — namely, the likely impact of alternative regulatory structures on promoting competition and economic efficiency over a long term horizon. The likely result would be a focus on word games associated with giving meaning to subtle differences in language, rather than on the economic substance of the decision. (sub. DR100, p. 39)

Some participants acknowledged that although the two terms could be defined, there might still be problems. The NCC noted:

> Regardless of any definition that might be developed to aid decision makers, the boundaries between something that is material and something that leads to a substantial improvement in competition would be difficult to discern. (sub. DR92, p. 8)

Similarly, Origin Energy considered:

> While it may be somewhat straightforward to make a legal distinction between either ‘material’ or ‘substantial’ competition relative to no competition; the perceived separation of intensity and scope between material and substantial would appear to be much less obvious. This lack of clarity is important; because each threshold implies a substantive change in regulatory regime with associated changes in commercial impacts to participants. (sub. DR83, p. 2)

Goldfields Gas Transmission also noted:

> The Commission is proposing to distinguish between the need for light and heavy-handed regulation and [Goldfields Gas Transmission] considers that this is a commendable and progressive move. However [Goldfields Gas Transmission] is concerned that no such clear, unambiguous or unassailable distinction between the meaning of the two words actually appears to exist in either common usage or jurisprudence. (sub. DR88, p. 8)

Some participants also raised concerns with the Commission's intended definition of 'likely' — whether its intention was 'a real chance' or 'more likely than not'. Enertrade considered that 'likely' was too low a threshold, and considered it more appropriate to use 'more likely than not' as it places 'a real burden on the decision maker to assess, and show, whether genuine benefits will arise from imposing statutory access regulation' (sub. DR98, p. 6). The NCC considered that if the Commission's intention was 'more likely than not' then it should explicitly include it in the criterion (trans., p. 672).

Inquiry participants generally supported the Commission's proposal for providing the NCC with guidance on interpreting criterion (a), although some considered it unnecessary. The Western Australian Government considered that, in general, it:

> … is satisfied that the NCC has established an informal process for the assessment of criterion 1.9(a), which has been comprehensively followed in coverage assessments. Nevertheless, some formal guidance in the [Gas] Code may provide for greater regulatory certainty in decision making. The amendment has the potential to facilitate greater transparency and consistency in the regulatory process, thus reducing the scope for conflict and improving the timeliness of the regulatory process. (sub. DR114, p. 8)

Worsley Alumina noted it:

> … does not oppose the adoption of some form of guidance on matters to consider in assessing the 'promotion of competition' test in coverage decisions. However, Worsley is unsure whether this guidance is strictly necessary as it considers that coverage decisions under the [Gas Access Regime] have generally been satisfactory. (sub. DR110, p. 14)

The NCC stated that it already considers a range of matters when making coverage decisions, so the Commission's proposal 'will have little practical effect' (sub. DR92, p. 9). It further noted that there can be dangers in prescribing the matters in such a way:

> First, the Commission has recommended an exhaustive list of matters to consider in assessing the 'promotion of competition' test. This would constrain the coverage analysis to those matters listed only. Accordingly, if the Commission proceeds with this recommendation, the [National Competition] Council suggests that an inclusive approach be adopted, similar to s.50 of the TPA. Section 50 commences with the words 'without limiting the matters' to make clear that the ACCC may take into account other relevant matters in addition to those listed.
>
> Second, listing the matters in 'black letter law' risks the need to resolve disputes over the statutory interpretation and weights that should be applied to the given factors listed. (sub. DR92, p. 9)

Other existing criteria

Some inquiry participants still considered the ‘uneconomic to develop another pipeline’ test (criterion [b]) should be expanded to address energy markets. Enertrade noted it ‘believes that the “uneconomic to duplicate” test should be widened to address the energy market, not just the so-called “point to point” services’ (sub. DR98, p. 2).

APIA was concerned that the Commission had not addressed the limitations of the interpretation of this criterion:

> APIA believes that the proper interpretation of (b) is that the criterion looks to the essentiality of the pipeline and the absence of substitutes to the service it provides. This interpretation confers on criterion (b) a substantive role in the assessment of the market power possessed by a pipeline. In turn, this enables a more realistic and less pivotal role for criterion (a) in the legislative scheme. (sub. DR100, p. 24)

AGL also considered that there might be a need for guidance in interpreting this criterion:

> … given that the relevant Minister raised concerns about the ‘point to point’ competition approach in the Moomba–Sydney pipeline revocation decision, there may be a need for guidance in assessing this criterion. Such guidance might say, for example, that the term ‘another pipeline’ does not mean a pipeline following exactly the same route. (sub. DR84, p. 8)

In relation to the ‘access provided without undue risk to health and safety’ test (criterion [c]), Origin Energy and the NCC both supported removing this criterion from the coverage criteria, with Origin Energy noting that it ‘also agrees that safety and health risk issues are more appropriately managed through other regulatory instruments’ (sub. DR83, p. 2). In contrast, APIA considered it should be retained, to maintain consistency with part IIIA and the CPA. It also noted:

> … whilst health and safety issues will generally not be significant, on the occasions when they arise it is most likely to be the case that they will be germane to the provision of access to the services provided by the facility. Accordingly, where these issues arise, it is appropriate that they are addressed at the coverage stage rather than in subsequent regulatory proceedings. (sub. DR100, p. 26)

There was little comment on the proposal to retain the ‘not be contrary to the public interest’ test (criterion [d]).

Proposed new efficiency test

Some participants commented on the Commission’s proposed new efficiency test (criterion [c] in box 6.3). The Western Australian Government noted it ‘concurs with Commission’s finding that a separate criterion may be appropriate given its relevance’ but raised concerns about interpretation of ‘significantly’ (sub. DR114, p. 6). AGL also supported the Commission’s intention behind the test, but noted:

> … the need for a common understanding of the concept of ‘a significant improvement in economic efficiency’ and how it will be applied in coverage assessments. The NCC and Ministers could be furnished with guidance in this regard. (sub. DR84, p. 9)

APIA also supported including an economic efficiency criterion, but still expressed concern at the lack of a national significance test:

> Whilst APIA strongly endorses the inclusion of an economic efficiency criterion, APIA submits that the Commission’s approach on this issue misses the point. It is precisely because the national significance test provides an efficient first pass filter that its inclusion in the coverage criteria is desirable. (sub. DR100, p. 26)

In contrast, WMC Resources considered:

> … criteria 1.9(a) and (b) currently encapsulate those factors relevant to considerations of economic efficiency … In WMC’s view, it is therefore unnecessary to include a separate economic efficiency test such as that proposed by the Commission. (sub. DR99, p. 16)

The NCC considered the proposed test appears to set the bar for coverage much higher than for declaration under the national access regime, and it replicates criterion (d):

> The proposed efficiency test unnecessarily replicates matters properly assessed under criterion (d) that coverage should not be contrary to the public interest. While the [National Competition] Council may have regard to matters other than economic efficiency when assessing the public interest, the prime focus of the test is economic efficiency. In determining coverage the decision maker must be affirmatively satisfied that criterion (d) and all other coverage criteria are met.
>
> Without evidence to demonstrate that a decision to cover a pipeline has occurred in marginal cases the Council can see no benefit in introducing a new test to guard against an unlikely event. (sub. DR92, p. 11)

Form of regulation

In addition to the comments above on the practicalities of using ‘material’ and ‘substantial’ in criterion (a) to decide on the form of regulation, some participants raised concerns with the proposed approach to deciding on the form of regulation.

The NCC considered there is merit in adopting an alternative to the current approach to regulation where appropriate, but had concerns with the appropriateness and practicality of using criterion (a) to help make the decision:

> The [National Competition] Council supports initiatives to provide greater flexibility in the Gas Access Regime. There is merit in adopting an alternative to the current price regulation option where it can be demonstrated to deliver appropriate outcomes at a lower cost. The Council does not, however, consider that it is necessary to largely pre-determine the decision on the form of regulation that should apply by the assessment under criterion (a). The principles of good regulatory practice require a full assessment of the costs and benefits of regulation. Under criterion (a) the Council assesses whether access or increased access to services provided by means of a pipeline would have the effect of promoting competition in upstream and downstream markets only. At this stage, it is yet to be determined whether there are any other relevant considerations that demonstrate that coverage is not contrary to the public interest. It would, therefore, seem premature to exclude price regulation as an option for addressing the market failure before all relevant factors have been considered.
>
> On this basis, the Council proposes that any decision about the form of regulation should be separate to and follow from the coverage decision and be determined on the basis of overall economic efficiency. The Council is in a good position to make an informed decision as to the appropriate form of regulation to recommend as the assessment against the full suite of coverage criteria would have a large bearing on any choice about the best form of regulation. Such an approach would also minimise implementation and adjustment costs by eliminating the need to alter the coverage criteria.
>
> In determining the form of regulation the Council would consider matters such as ownership structures, the nature of competition in the market and demand characteristics. Where, for example, vertical integration is not an issue and there are a limited number of access seekers, it is likely that an alternative to the current access arrangements could operate effectively. (sub. DR92, p. 11)

WMC Resources also considered the decision should be at the discretion of the NCC, but guidelines could be used:

> The decision as to what form of regulation should apply in any instance should be left to the discretion of the NCC, which it should exercise having regard to the specific circumstances of the individual case. Guidelines could be used to indicate factors to be taken into account. (sub. DR99, p. 15)

Processes for moving between types of regulation

Pipeline owners generally supported the Commission’s proposal to restrict applications for coverage for uncovered pipelines to access seekers that demonstrate they have undertaken ‘best endeavours’ in commercial negotiations that failed. For example, Enertrade (sub. DR98, pp. 4–5), AGL (sub. DR84, p. 12) and the Energy

Networks Association (sub. DR85, p. 14). Goldfields Gas Transmission also supported the approach, but noted the difficulty in demonstrating this:

> The difficulty however is in determining how 'best endeavours' can be demonstrated in circumstances where one party has no interest in negotiation but is merely seeking grounds for intervention. (sub. DR88, p. 13)

Envestra suggested the supply of the following information would assist in determining whether best endeavours have been used in negotiating access:

> (a) copy of access request submitted to service provider
>
> (b) copy of reply to access request
>
> (c) from each of service provider and prospective user, chronological summary of process and correspondence, and reason(s) why negotiations have failed. (sub. DR82, p. 9)

ExxonMobil supported the proposal, and noted it:

> … believes that the [Gas] Code should provide guidance in this area which directs the regulator to examine the process of negotiation rather than simply a failure of the parties to agree a tariff price. The guidance could include the legal concepts of 'good faith' in negotiations. The guidance could further include an expectation that the access seeker would have been afforded fair, impartial and timely treatment by the pipeline owner/operators. (sub. DR78, pp. 4–5)

The South Australian Government did not support the proposal, and stated:

> It may be that an unsuccessful access seeker's commercial interests do not compel them to apply for coverage, especially as it would signal their unsuccessful access attempt to the market. The public interest in curbing the exercise of monopoly power by service providers could see a need for other parties such as governments or user groups to apply for a pipeline to be covered by the regime.
>
> If [the Commission's proposal] were to be implemented, it could be problematic for a party to demonstrate that it has undertaken 'best endeavours' in its negotiations with the service provider, with the potential for litigation. (sub. DR108, p. 4)

The Economic Regulation Authority (which has assumed the responsibilities of the former Office of Gas Access Regulation, OffGAR) noted:

> … it will remain extremely difficult, if not impossible, for an access seeker to demonstrate best endeavours in negotiation with any service provider that is outside the regulatory regime of the [Gas] Code. (sub. DR116, p. 16)

There was little comment on the Commission's proposal to retain the current approach for revocation — that is, no restrictions on either when applications can be made or who can apply. AGL (sub. DR84, p. 13) and Goldfields Gas Transmission (sub. DR88, p. 14) both supported this approach.

Other issues

Inquiry participants supported the Commission's proposal to reduce forum shopping, for example, AGL (sub. DR84, p. 14), Western Power (sub. DR115, p. 34) and the NCC (sub. DR92, p. 2). Worsley Alumina considered 'this is likely to promote efficient management of applications' (sub. DR110, p. 15).

Unlike part IIIA of the TPA, the Gas Code provides for coverage of physical pipelines rather than specific services provided by pipelines. The NCC suggested that there might be merit in moving towards coverage of services rather than physical pipelines, although it noted:

> To date, this issue has not been subject to significant consideration. The primary reason for this is that in almost all cases of coverage and revocation, the competitive environment for the entire suite of services offered by a pipeline has essentially been identical. The [National Competition] Council and the [Australian Competition] Tribunal have largely concentrated on point-to-point gas haulage services in applying the coverage criteria (see Duke decision). The presumption has been that if the coverage test is satisfied in respect of the principal pipeline activity of gas haulage between two points, it would be satisfied in respect of other services provided by that pipeline.
>
> The Council anticipates that the situation may change as more competition emerges, such that competitive conditions may differ across the services offered by pipeline operators. (sub. DR92, p. 17)

The NCC later noted:

> Our interest is in avoiding overregulation and if by tuning regulation or coverage to a service rather than to the physical pipeline asset directly, we can in appropriate cases craft a degree of coverage that would be less, that is, that would be enough to cover the bits that were of concern to us in terms of the criteria but did not cover other parts or other services provided by the pipeline, we think that that would be a positive increase in flexibility. Practically we're not entirely sure that it would make a huge difference although, depending on the outcome of various latter proceedings in relation to the [Moomba–Sydney pipeline], there is some prospect that service from one point to a particular point along a pipeline or a spur off a pipeline might be a service that would deserve coverage but service to another point might not. (trans., p. 659)

6.7 Assessment and recommendations

There is need for considerable caution when proposing changes to legislated criteria. Making changes to reflect a particular interpretation more accurately can be risky, given judicial interpretation of those changes, as acknowledged in the Commission's review of the national access regime:

> … in their responses to the position paper, the legal fraternity adopted a much more conservative and cautious stance. Some contended that making even minor amendments to the declaration criterion to reflect more accurately a particular interpretation would be fraught with risk. They suggested that the courts would be likely to interpret such amendments from the standpoint that a change in policy 'direction' must have been intended. (PC 2001c, p. 160)

The ACCC commented that the existence of this case history provides a rationale for not departing from the current regulatory framework since a 'departure from the present framework would add to, and not decrease, regulatory uncertainty' (ACCC, sub. 48, p. x). It is certainly true that through coverage decisions, and the cases heard in the Australian Competition Tribunal, a case history has developed. However, it is the Commission's view that a collection of case history does not provide a sufficient basis for retaining the Gas Access Regime in its current form.

The Commission is mindful of the risks of changes to the coverage criteria and of the transitional costs that might be incurred from a change in the regime, but also considers that if there is a strong case to make changes, they should be made. Of course changes should be designed to try to minimise unnecessary risks and costs.

Transmission pipelines and distribution networks

As outlined in chapter 2, transmission pipelines and distribution networks have different characteristics and can vary in their significance and in the extent to which service providers have (and can exert) market power. Interested parties noted that the existing regime is sufficiently flexible to manage these differences. A persuasive case has not been made for having two separate regimes. There was broad agreement on this issue following the release of the draft report.

The Commission considers there is no case for separate coverage criteria for transmission pipelines and distribution networks. The framework proposed by the Commission is capable of dealing with the market circumstances of both transmission and distribution pipelines on a case-by-case basis. The NCC is required to account for the impact on overall economic efficiency (through the 'not be contrary to the public interest' test), as well as the market power of the service provider.

FINDING 6.2

Different coverage criteria for transmission pipelines and distribution networks are not warranted. The coverage criteria should be sufficiently flexible to deal with such differing circumstances.

Pipelines listed in schedule A

Prior to the draft report, some inquiry participants raised concerns that pipelines listed in schedule A of the Gas Code did not have a transparent assessment of whether they met the coverage criteria. Subsequently, service providers and governments have had to incur costs in the revocation process. The Commission acknowledges that the revocation of 13 transmission systems (in whole or in part), and six distribution networks (chapter 3) *prima facie* suggests some pipelines were inappropriately included in schedule A.

However, this is a transitional issue. Any new pipelines that are built cannot be added to schedule A of the Gas Code. Rather, if someone seeks coverage, the NCC must assess the application against the coverage criteria (unless the service provider submits voluntarily an access arrangement or seeks approval for a competitive tender process). The Commission acknowledges that there might have been a less than rigorous process for the preparation of schedule A of the Gas Code. That is, some pipelines might have been covered inappropriately. This is a transitional issue, and can be addressed through the ongoing revocation process.

Modifying the coverage criteria

The Australian Government released its final response to the Commission's review of the national access regime on 20 February 2004. This occurred after the release of the Commission's draft report and has significant implications for the Commission's deliberations on modifying the coverage criteria. In its response it announced changes to one of the criteria for declaration under the national access regime (the criterion in relation to promotion of competition) (box 6.4), which has important implications for the Gas Access Regime coverage criteria, due to their interaction through certification of industry-specific regimes.

As outlined in chapter 3, where certification of the Gas Access Regime occurs (that is, it is consistent with the CPA), access seekers cannot use part IIIA to seek access to pipelines that are already covered under the Gas Access Regime. On the other hand, access seekers can use part IIIA to seek access to uncovered pipelines. As noted by the NCC, the current similarities between the coverage criteria and declaration criteria remove the potential for uncovered pipelines to be declared. However, if the criteria in the Gas Access Regime were to be modified such that the hurdle would be higher than part IIIA, then there would be the potential for uncovered pipelines to be declared under the national access regime.

> The current coverage criteria in the national Gas Access Regime are substantially the same as the declaration criteria in part IIIA of the TPA. This means that pipelines that do not meet the criteria for coverage under the national Gas Access Regime also would

> not meet the criteria for declaration under part IIIA. If the coverage criteria were to be amended so that the hurdle for coverage was higher than the hurdle for declaration, it would be possible that some pipelines may not meet the criteria for coverage, but would meet the criteria for declaration. Once again, this would need to be determined in the context of particular applications. (NCC, sub. DR117, p. 1)

FINDING 6.3

If the threshold for coverage under the Gas Access Regime were higher than that for declaration in the national access regime, pipelines that do not satisfy the coverage criteria under the Gas Access Regime could be declared under the national access regime if they were to satisfy the declaration criteria.

Box 6.4 **Review of the national access regime — 'promotion of competition' test**

Review recommendations

The Commission's review of the national access regime proposed a range of modifications to the architecture of part IIIA of the TPA to ensure access regulation is better targeted and more workable.

In relation to the 'promotion of competition' test, the Commission recommended:

> Clause 44G(2)(a) of the Trade Practices Act should be amended such that access (or increased access) to the service would promote a *substantial* increase in competition in at least one market (whether or not in Australia), other than the market for the service. If it is considered that the inclusion of the word 'substantial' carries a concomitant requirement for greater certainty of the outcome, an explicit concept of likelihood may need to be embodied in the revised criterion. (PC 2001c, p. 192)

Government's final response

The Australian Government agreed in principle with the Commission's recommendation, but replaced 'substantial' with 'material', explaining:

> The current declaration criteria, such as 'the national significance' test, preclude declaration where the relevant infrastructure and subsequent potential public benefits are not significant. However, this does not sufficiently address the situation where, irrespective of the significance of the infrastructure, declaration would result in only marginal increases in competition.
>
> The Government considers that, in this context, the term 'substantial' may exclude situations where a small supplier is prevented from gaining access to nationally significant infrastructure. The Government therefore proposes to include the word 'material' to ensure access declarations are only sought where the increases in competition are not trivial. (Costello 2004, p. 7)

Sources: Costello 2004; PC 2001c.

In chapter 4, the Commission considered that a national framework that accounts for the specific characteristics of the gas market is likely to involve lower transaction costs and larger benefits than relying on the national access regime. Further, there is likely to be more than one access seeker for some pipelines. A generally available access arrangement for such pipelines is likely to involve lower costs than those of requiring each access seeker to seek access through the negotiate–arbitrate framework of the national access regime. Thus, the Commission found that an industry-specific national access regime is appropriate for gas transmission pipelines and distribution networks.

The Commission considers that if a pipeline has been assessed against the coverage criteria and it has been determined that this pipeline does not meet the coverage criteria (that is, it is an uncovered pipeline), then access to such a pipeline should not be regulated, whether by the Gas Access Regime or the national access regime. That is, the Gas Access Regime should have primacy for natural gas transmission pipelines and distribution networks.

FINDING 6.4

In circumstances of there being a specific Gas Access Regime, it is desirable for this regime to have primacy over the national access regime.

To ensure that the Gas Access Regime has primacy over the national access regime, the threshold for coverage under the Gas Access Regime should be no higher than the threshold for declaration under the national access regime.

Consequently the Commission considers that the coverage framework for the Gas Access Regime be made essentially the same as the declaration criteria for the national access regime. This would ensure that a pipeline not covered under the Gas Access Regime will not be declared under the national access regime.

RECOMMENDATION 6.1

The Gas Access Regime coverage criteria should provide the same threshold for coverage as declaration under the national access regime, such that a pipeline not satisfying the coverage criteria of the Gas Access Regime also will not satisfy the declaration criteria of the national access regime.

Currently, the coverage criteria are essentially the same as the declaration criteria for the national access regime. (The main difference is that the national access regime has an additional national significance test.) In the absence of change to part IIIA, retaining the existing coverage criteria for the Gas Access Regime would ensure that a pipeline not satisfying the existing coverage criteria under the Gas Access Regime will not be declared under the national access regime.

However, in light of the Australian Government’s proposed change to the declaration criteria for the national access regime, the Commission considers that coverage criterion (a) of the Gas Access Regime should be similarly changed.

RECOMMENDATION 6.2

The first criterion for assessing coverage (s.1.9[a] of the Gas Code) should be amended to reflect the Australian Government’s proposed change to s.44G(2)(a) in part IIIA of the Trade Practices Act (the national access regime). That is, that the National Competition Council would need to be satisfied:

(a) that access (or increased access) to Services provided by means of the Pipeline would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline.

The Minister would also be bound by this change as per s.1.15 of the Gas Code.

The remaining three coverage criteria are the ‘uneconomic to develop another pipeline’ test (criterion [b]), ‘access provided without undue risk to health or safety’ test (criterion [c]), and the ‘not be contrary to the public interest’ test (criterion [d]) (box 6.1).

These criteria are also essentially the same as those in the declaration criteria for part IIIA. In its response to the review of the national access regime, the Australian Government did not propose to change any of these criteria in the declaration criteria. Therefore the Commission considers that the remaining coverage criteria should be retained, thereby directly aligning the coverage criteria for the Gas Access Regime with the declaration criteria for part IIIA. Compared with the draft report, the Commission is therefore adding back in criterion (c) relating to health and safety.

FINDING 6.5

The following criteria should be retained in the coverage criteria (s.1.9 of the Gas Code):

(b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline

(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

(d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

National significance test

The declaration criteria in part IIIA of the TPA include a criterion that the facility be of national significance. The Gas Access Regime does not have any similar criterion.

The NCC might not recommend coverage under the Gas Access Regime for a pipeline that is not nationally significant, if the NCC considers that the costs of regulation outweigh the benefits (that is, in its assessment of the 'not be contrary to the public interest' test). However, there remains a possibility that pipelines that are not nationally significant could be covered under the Gas Access Regime, but would not be declared under part IIIA.

The Commission's recommended coverage criteria for s.1.9 of the Gas Code are summarised in box 6.5.

Box 6.5 **Recommended coverage criteria for the Gas Code**

The Commission recommends replacing s.1.9 of the Gas Code with the following proposed coverage criteria:

> Subject to sections 1.4(a) and 1.10, the NCC must recommend that the Pipeline be Covered (either to the extent described, or to a greater or lesser extent than that described, in the application) if the NCC is satisfied of all of the following matters, and cannot recommend the Pipeline be Covered, to any extent, if the NCC is not satisfied of one or more of the following matters:
>
> (a) that access (or increased access) to Services provided by means of the Pipeline would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline;
>
> (b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline;
>
> (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
>
> (d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

Form of regulation

Currently, the service provider of a covered pipeline must fulfil all of the requirements of the Gas Code (including having a regulator approved access arrangement with reference tariffs). The Commission describes in chapter 8 how a light-handed regulatory approach could deliver appropriate outcomes at a lower cost in some circumstances, and it recommends making a monitoring option available for some covered pipelines. That is, two alternative forms of regulation (a light-handed monitoring option and access arrangements with reference tariffs) should be available to covered pipelines.

Allowing for two forms of regulation raises some issues:

- When and who should make the decision on the form of regulation to apply to a covered pipeline?
- How to decide between application of the monitoring option and access arrangements with reference tariffs?

When and who should make the decision on the form of regulation

A decision on the form of regulation needs to weigh up the benefits and costs of the two different forms of regulation. The coverage decision currently involves an assessment of benefits and costs of the current form of regulation. The Commission considers it would be desirable for the assessment and decision on the form of regulation to be a part of, but follow from, the assessment and decision on coverage.

It is important that policy-type functions are separate from administrative-type regulatory functions (institutional arrangements are discussed in chapter 12). Consequently, the Commission considers that the NCC should continue to recommend whether a pipeline should be covered, and also recommend on the form of regulation to apply, with the Minister making both decisions following the NCC's recommendations. This approach is supported by the NCC, which considered it is in a good position to make an informed decision as to the appropriate form of regulation (sub. DR92, p. 11).

The Commission also considers that the form of regulation decision be covered by similar administrative processes to the coverage decision, such as public consultation and merits appeal.

RECOMMENDATION 6.3

The Gas Access Regime should be modified such that the Minister and National Competition Council, in making a decision and recommendation, respectively, to cover a pipeline, should also decide and recommend, respectively, the form of regulation to apply.

How to decide on the form of regulation

As noted, the Commission considers that the potential net economic benefits from regulation should dictate the form of regulation. The monitoring option (discussed in chapter 8) is designed to impose lower costs than access arrangements with reference tariffs. On the other hand, applying the monitoring option where a service provider has substantial market power in a substantial market is likely to involve lower benefits (from reducing inefficiency from monopoly pricing in the gas transportation market and promoting competition in upstream and downstream markets) than applying access arrangements with reference tariffs.

The Commission considers that the recommendation and decision on which form of regulation to apply should consider the costs and benefits of both forms of regulation. Given the costs of access arrangements with reference tariffs (including the potential for distorted investment), it is important that such regulation is applied to transmission pipelines and distribution networks only where there are clearly greater net benefits to the economy. Therefore, the Commission considers that the decision and recommendation on the form of regulation to apply should err on the side of coverage with monitoring. Regulation with access arrangements with reference tariffs should be applied only where the net benefits of access arrangements with reference tariffs are markedly greater than the net benefits of the monitoring option. Where the difference in net benefits are marginal or the net benefits of the monitoring option are greater than the net benefits of access arrangements with reference tariffs, then the monitoring option should be applied.

This framework of using the net economic benefits to decide on the form of regulation in effect incorporates the efficiency test that the Commission proposed in the draft report. In the draft report, the coverage criteria were designed to do two tasks — assess whether a pipeline should be covered as well as the form of regulation to apply. The Commission's current approach is to less closely link the form of regulation decision to the coverage criteria, although it is integrally related. The net benefits assessment for the form of regulation is essentially the Commission's efficiency test by another name.

RECOMMENDATION 6.4

The decision and recommendation on the form of regulation to apply should be based on an assessment of the net benefits to the economy of each form of regulation (an access arrangement with reference tariffs or monitoring option). Access arrangements with reference tariffs should be applied only where the net benefits of its application are markedly greater than the net benefits of the monitoring option. Otherwise the monitoring option should be applied.

An illustration of how such an assessment could be undertaken is the assessment of mergers in the TPA. Section 50 of the TPA explicitly lists nonlimiting matters that must be taken into account in determining whether mergers 'would have the effect, or be likely to have the effect of substantially lessening competition in a market' (box 6.6). Moreover, the Commission suggested some criteria that might provide guidance in evaluating the significance of monopoly power in its review of the *Prices Surveillance Act 1983* (PC 2001d, p. 88). In its review of telecommunications competition regulation, the Commission recommended amending the relevant legislation to provide the ACCC with more explicit guidance on matters to consider when assessing competition and market power in a declaration inquiry (PC 2001e, p. 283).

Box 6.6 **Matters to consider when determining mergers — s.50 of the TPA**

Section 50 of the TPA states:

> Without limiting the matters that may be taken into account for the purposes of subsections (1) and (2) in determining whether acquisition would have the effect, or be likely to have the effect of substantially lessening competition in a market, the following matters must be taken into account:
>
> (a) the actual and potential level of import competition in the market;
> (b) the height of barriers in the market;
> (c) the level of concentration in the market;
> (d) the degree of countervailing power in the market;
> (e) the likelihood that the acquisition would result in the acquirer being able to significantly and sustainably increase prices or profit margins;
> (f) the extent to which substitutes are available in the market or are likely to be available in the market;
> (g) the dynamic characteristics of the market, including growth, innovation and product differentiation;
> (h) the likelihood that the acquisition would result in the removal from the market of a vigorous and effective competitor;
> (i) the nature and extent of vertical integration in the market.

Providing guidance to the Minister and the NCC on factors to consider in deciding and recommending on the form of regulation to apply to a particular pipeline can improve the consistency of decisions, help align the decisions with the Gas Access Regime's objectives, reduce business uncertainty about the form of regulation to be applied, and provide assurance that the appropriate factors are identified. The net economic benefits assessment essentially would be one of judgment, rather than pursuing specific quantification of the various benefits and costs.

FINDING 6.6

There would be benefits from improved consistency and reduced uncertainty if the Minister and the National Competition Council were provided with guidance on the matters to be considered when deciding and recommending, respectively, which form of regulation should apply.

An important consideration in assessing the benefits from regulating pipelines is the extent to which service providers have market power. Regulation to reduce the exercise of that power generates benefits from reducing inefficiencies from monopoly pricing in the gas transportation market and promoting competition in upstream and downstream markets. As discussed in chapter 2, there are various factors that can influence the market power of a service provider, including the nature of demand, actual and potential competition from substitutes (such as gas from other pipelines or other energy sources), barriers to entry and the bargaining power of users.

An important factor in assessing the actual and potential competition from substitutes is the ownership of those substitutes. That is, competitive pressure on pipelines might be weak if there is concentration of ownership either horizontally or vertically. Therefore, its important to take into account the degree of horizontal and vertical ownership in determining benefits of regulation. (The NCC also considered ownership structures are an important consideration in determining the form of regulation to apply — sub. DR92, p. 11.)

Thus, the Commission considers that the following factors are important considerations in determining the market power, and consequent benefits of regulation, of a particular pipeline:

- the nature of demand for the commodities and services of end users of gas
- the actual and potential level of competition from substitutes such as gas from other sources delivered through other pipelines, and other forms of energy such as electricity
- the nature and extent of any barriers to entry in the market
- the degree of countervailing power in the market
- the degree of horizontal and vertical integration.

Although the Commission considers that these factors are important to consider in determining the potential benefits of regulation, it does not consider that the above list is exhaustive. That is, the Minister and the NCC should not be constrained to consider these factors only. Nonetheless, as noted in chapter 5, there can be costs in providing too much discretion. Consequently, the Commission proposes that the Minister and the NCC be able to consider other significant factors, but only to the extent that these other factors are consistent with the proposed new objects clause.

In relation to factors to consider in weighing up the costs of the two forms of regulation, the Commission considers the structure presented in chapter 4 is a reasonable framework. That is, the NCC and the Minister should consider:

- direct costs — including service providers' compliance costs, government administration costs and users' costs
- other costs — including distortions in behaviour arising from timeliness, regulatory risk and regulatory error (such as the inherent difficulties in determining efficient costs for services).

These costs are discussed in further detail in chapter 4.

This list is not exhaustive and the Minister and the NCC should take into account any other significant factors that are consistent with the proposed new objects clause.

RECOMMENDATION 6.5

The Gas Access Regime should be amended to give guidance on matters that the Minister and the National Competition Council should consider in deciding and recommending, respectively, which form of regulation should apply to a covered pipeline.

In determining the potential benefits of either form of regulation, the following matters should be taken into account:

(a) the nature of demand for the commodities and services of end users of gas

(b) the actual and potential level of competition from substitutes such as gas from other sources delivered through other pipelines, and other forms of energy such as electricity

(c) the nature and extent of any barriers to entry in the market

(d) the degree of countervailing power in the market

(e) the degree of horizontal and vertical integration

(f) any other significant factors, subject to them being consistent with the proposed new objects clause.

In determining the potential costs of either form of regulation, the following matters should be taken into account:

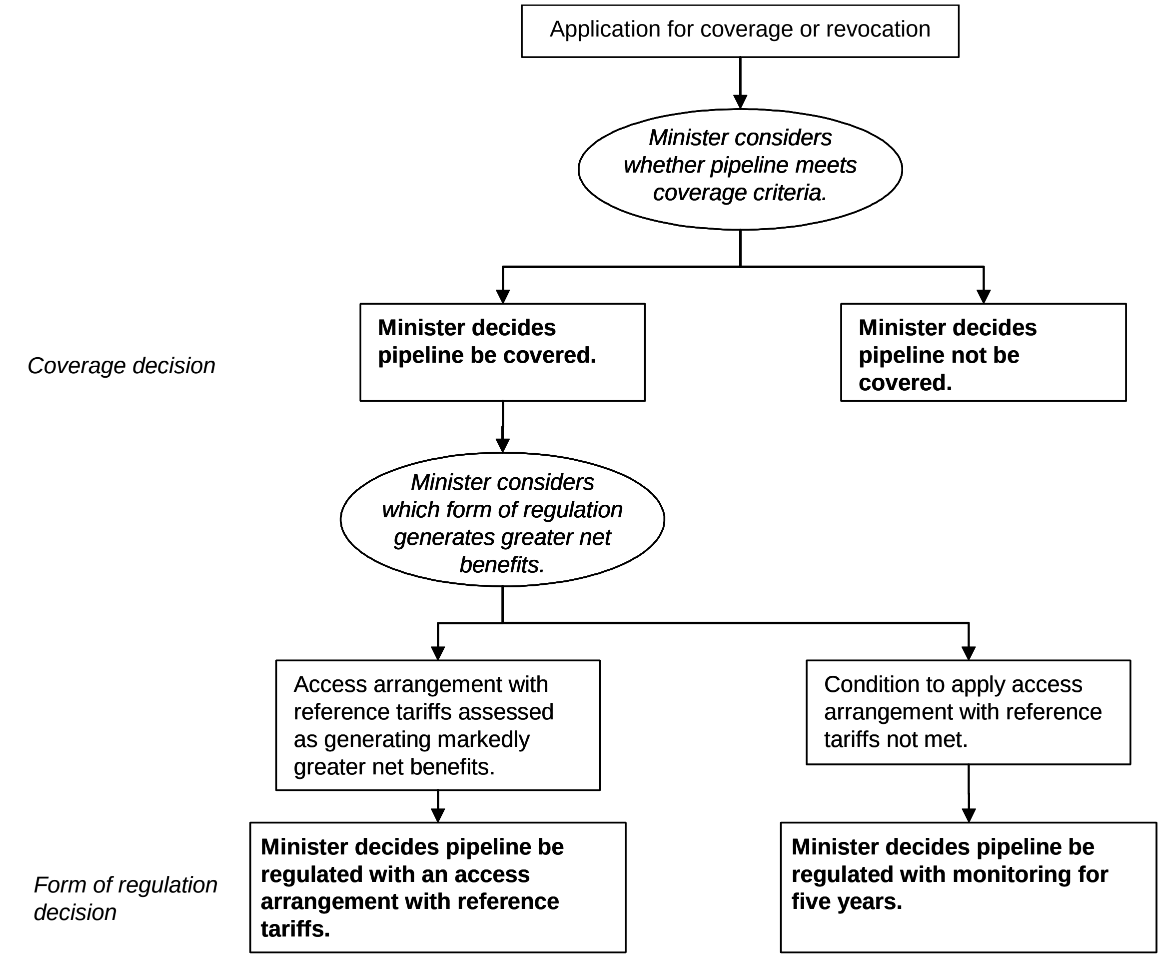
(a) direct costs of service providers, governments and users

(b) other costs (for example, distortions in behaviour arising from timeliness, regulatory risk and regulatory error (such as the inherent difficulties in determining efficient costs for services))

(c) any other significant factors, subject to them being consistent with the proposed new objects clause.

The process the Minister would follow in deciding on an application for coverage or revocation and the form of regulation to apply to a covered pipeline is summarised in figure 6.2. (The NCC should follow a similar process in recommending coverage or revocation and the form of regulation to apply.) Transitional issues for pipelines currently covered with access arrangements with reference tariffs are discussed in chapter 8.

Figure 6.2 **Proposed framework for deciding coverage and form of regulation[a]**



[a] The National Competition Council follows an identical process in recommending to the Minister whether a pipeline should be covered, and if so, what form of regulation should apply.

Processes for moving between types of regulation

Under the existing Gas Access Regime, decisions about whether a pipeline is covered can be made repeatedly over time, through applications for coverage and revocation. Currently, there are no restrictions on when a person can apply for coverage or revocation of coverage of a pipeline. The owners of the

Moomba–Sydney pipeline have applied twice for revocation of coverage (appendix C). A benefit of this approach is that a service provider, when facing a material change in circumstances, can seek a revocation in coverage without having to wait for the expiry of a mandatory coverage period. Similarly, access seekers can seek coverage of a pipeline without having to wait for the expiry of a mandatory period where a pipeline is not covered. There are also no restrictions on who can apply for coverage of a pipeline. Any person — whether a service provider, regulator, user or any other person — can apply for coverage.

If the monitoring option recommended in chapter 8 was included in the Gas Access Regime, applications to the NCC could be for the following types of pipeline:

- those that are not covered
- those that are covered with the monitoring option
- those that are covered with an access arrangement that includes reference tariffs.

The way in which the proposed framework would work for uncovered pipelines and pipelines covered with an access arrangement with reference tariffs is discussed below. The processes for when monitoring is being applied, including when and who can apply for revocation and coverage with access arrangements with reference tariffs, is discussed in chapter 8.

Applications for pipelines that are not covered

In the draft report the Commission saw no reason to vary the current approach of allowing applications for coverage for uncovered pipelines at any stage. In terms of who could apply for coverage, the Commission raised the possibility of limiting applications to access seekers that demonstrate they have undertaken 'best endeavours' in commercial negotiations that failed. Some inquiry participants supported the Commission's proposal in the draft report.

Such an approach could reduce the potential for strategic behaviour by access seekers under the existing regime. The NCC can stop an application process if it concludes that an application is trivial or vexatious. The NCC might thus have scope to reject an application on these grounds from a nongenuine access seeker. The scope for such strategic behaviour might be limited to some extent by the costs of application ($7500 at a minimum, with higher costs possibly, particularly if the decision is appealed).

However, limiting applications to access seekers who demonstrate they have undertaken 'best endeavours' in commercial negotiations and failed would add costs at the start of an application to:

- the applicant (in undertaking commercial negotiations and then demonstrating they have undertaken those negotiations)
- the service provider (in undertaking commercial negotiations)
- the NCC (in assessing whether applicants meet this requirement).

Given the potential for cost savings from avoiding regulation if service providers and access seekers can agree on terms and conditions via negotiation, the Commission considers that some negotiation costs to applicants and service providers would not be inappropriate. There can also be difficulties in trying to implement such a screening. Also, importantly, introducing such a screen would mean the approach under the Gas Access Regime is different from the national access regime (which states that 'The designated Minister, or any other person, may make a written application'). This might provide an incentive to make applications under the national access regime rather than the Gas Access Regime. As concluded earlier, the Commission considers that the Gas Access Regime should have primacy over the national access regime.

On balance the Commission concludes that there is not a case to change the current arrangements, given:

- the potential costs of limiting applications to access seekers that demonstrate they have undertaken 'best endeavours' in commercial negotiations and failed
- the potentially limited benefits
- the interaction with the national access regime.

That is, any person should be able to apply for coverage of uncovered pipelines. It also concludes there is no reason to vary the current approach of allowing applications at any time.

Applications for pipelines that are covered with an access arrangement with reference tariffs

For a pipeline covered with an access arrangement with reference tariffs, applications to the NCC relate to revocation of coverage (with possible outcomes being the NCC recommending retaining coverage with an access arrangement with reference tariffs, coverage with the monitoring option or revocation). The Commission considers the current arrangements should be maintained. That is, there be no restrictions on either *when* applications can be made or *who* can apply.

Other issues

Forum shopping

A service provider has scope to submit an undertaking under part IIIA of the TPA when coverage under the Gas Code has not been determined. The Commission also considered this issue in its review of the national access regime (box 6.7).

Box 6.7 **Review of the national access regime — forum shopping**

Review recommendations

In its review of the national access regime, the Commission recommended streamlining the coverage criteria applying across the regime's different access routes. Specifically, the Commission recommended (PC 2001c, pp. 276–7):

- amending the Gas Code to provide that where a pipeline owner potentially covered by the Gas Code lodges a part IIIA undertaking, this should trigger an assessment by the NCC to determine whether the pipeline meets the requirements for coverage under the Gas Code. The ACCC assessment of the part IIIA undertaking should be held over, pending the outcome of the NCC's inquiry
- amending part IIIA to make it explicit that the ACCC cannot accept an undertaking if the service concerned is subject to a certified access regime.

Government's final response

The Government's final response to the inquiry agreed in principle with the first recommendation and agreed with the second recommendation (Costello 2004, p. 13).

Sources: Costello 2004; PC 2001c.

The Commission considers that infrastructure services should not be exposed to the possibility of double regulation. It thus reiterates the conclusion and recommendation from its review of the national access regime. That is, a part IIIA undertaking should not be accepted where coverage under the Gas Code has yet to be resolved (PC 2001c, pp. 275–6).

RECOMMENDATION 6.6

The Gas Access Regime should be amended to provide that where a service provider potentially covered by the Gas Code lodges a part IIIA undertaking, this should trigger an assessment (currently by the National Competition Council) and decision (by the Minister) on whether the pipeline meets the requirements for coverage under the Gas Code. The Australian Competition and Consumer Commission's assessment of the part IIIA undertaking should be held over, pending the outcome of the triggered coverage assessment and decision.

Coverage of services versus coverage of pipeline

Following the release of the draft report, the NCC suggested in its submission and at public hearings there might be merit in moving towards coverage of services rather than physical pipelines, although it noted this had not yet been an issue (sub. DR92, p. 17).

The NCC considered that as more competition emerges, the competitive conditions might differ across the services offered by service providers. As an example, it noted that a spur off a pipeline might be a service that would deserve coverage but service to another point might not. However, the Commission considers that generally the current arrangement could deal with such a situation. The Minister's decision on revocation of parts of the Moomba–Sydney pipeline, for example, separated the pipeline into geographic sections and covered only those sections of the pipeline that were considered to meet the coverage criteria (Macfarlane 2003a).

As noted by the NCC, there would be important issues to be addressed if such a change were to be implemented, such as considering service definitions within the Gas Code and the implications for other provisions, such as ring fencing (NCC, sub. DR92, p. 18).

The Commission is making various recommendations to improve the performance of the regime. These are expected to address many of its weaknesses. At this point in time, it is difficult to see the residual issues that moving to a coverage of services approach would address. Nonetheless, it might be an issue to consider in any future review of the Gas Access Regime.

7 Access arrangements

This chapter examines issues relevant to the content of access arrangements as they are currently specified under the reference tariff approach of the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime). The contents of an access arrangement may include any matter relevant to third party access to a pipeline. However, as a minimum, the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) requires an access arrangement to contain the elements listed in box 7.1.

Box 7.1 **Minimum requirements for an access arrangement**

An access arrangement must contain at least the following elements:

- A **services policy** — including a description of one or more services that are likely to be sought by a significant part of the market, and any which in the regulator's opinion should be included. The services policy should also allow, where reasonable and practical, prospective users to obtain, and be charged a separate tariff for, only the elements of a service that they want.
- A **reference tariff** for at least one service that is likely to be sought by a significant part of the market, including all such services that the regulator considers should have a reference tariff.
- A **reference tariff policy** — describes the principles used to set reference tariffs, which must comply with the requirements in s.8 of the Gas Code.
- The **terms and conditions of supply** for each service with a reference tariff.
- A **capacity management policy** — a statement that the covered pipeline involves either contract or market carriage.
- A **trading policy** — for contract carriage pipelines, explains the rights of a user to trade their entitlement to a service to another person.
- A **queuing policy** — determines the priority that a prospective user has to access spare and developable capacities, where such access may impede the ability to provide a service sought, or which may be sought, by another prospective user.
- An **extensions/expansions policy** — specifies the method for determining whether or not a pipeline extension or capacity expansion is to be treated as part of the covered pipeline for all purposes under the Gas Code.
- A **revisions submission date** and **revisions commencement date** — the dates when a service provider must submit revisions to its access arrangement, and when the next revisions are intended to commence.

In broad terms, most of this chapter examines how regulated access prices — termed reference tariffs — are determined; with the remainder of the chapter focused on the non price elements listed in box 7.1. More specifically, the chapter comprises the following sections:

- Section 7.1 outlines the broad approach used to set reference tariffs.
- Section 7.2 considers the use of specific objectives (pricing principles) to guide the determination of reference tariffs.
- Section 7.3 analyses the current (building block) method used to calculate reference tariffs and whether other approaches should be allowed.
- Section 7.4 outlines the issues relevant to valuing a service provider's capital base.
- Section 7.5 examines how the *ex ante* regulatory rate of return is determined.
- Section 7.6 analyses the Gas Code provisions that enable the use of a competitive tender to set reference tariffs.
- Section 7.7 examines the requirements for service providers to give business information to regulators.
- Section 7.8 analyses capacity management and trading, and the treatment of extensions and expansions of covered pipelines.
- Section 7.9 summarises the findings and recommendations resulting from the above.

7.1 Broad approach used to set reference tariffs

If direct intervention is seen as necessary to prevent anticompetitive pricing, then there are various regulatory approaches that can be used (box 7.2). These approaches modify a business's behaviour by imposing constraints on the prices it can charge and/or the revenue it can earn. All of the approaches have limitations.

A common problem with the regulatory approaches outlined in box 7.2 is the marked information asymmetry between regulators and businesses. Regulators are not well informed about the operations of individual businesses and so depend on detailed information provided by the businesses they regulate, such as forecast demand and operating costs. There can be sizeable costs in preparing such information in the format required by a regulator (discussed in section 7.7).

Box 7.2 Options to directly control prices/revenue

Cost-based regulation — regulated prices are based on the cost of production. This could involve setting prices so as to provide a fixed mark-up on costs. Another approach is to provide for a 'fair' rate of return on capital costs that encourages ongoing supply but prevents excess profits. A drawback of cost-based regulation is that it provides little incentive to increase efficiency. A profit sharing arrangement can address this problem to some extent, by enabling businesses to keep some efficiency gains beyond the time when a regulator next resets prices.

Price caps — a limit is imposed on a regulated business's prices. Price caps can provide greater flexibility in pricing behaviour than cost-based regulation. For example, a price cap can be applied to just the business's (revenue) weighted average price, giving some flexibility about prices charged for individual services and/or customers. In Australia, price caps are often specified as a constraint on price growth, known as CPI-X regulation. This involves limiting price growth to the rate of change of the Consumer Price Index less an X factor, where the X predominantly accounts for expected productivity improvements.

Price caps have been described as light-handed regulation because, in theory, they do not require the regulator to undertake a detailed examination of a business's costs or to set prices for every service provided by a business (Littlechild 1983). In practice, there is a tendency over time for price caps to converge to cost-based regulation, with many of its associated incentive problems (PC 2002b). This is because price caps have to be reset periodically with reference to actual costs in order to ensure they are realistic. Price caps have also been described as 'incentive regulation' because a business can benefit from any cost reductions in excess of those implicit in its price cap. However, this incentive is diluted if regular price cap resets or benefit sharing mechanisms incorporate actual cost reductions into the price cap.

Revenue caps — the regulator imposes a limit on a regulated business's revenue. This can be designed so as to give a business some flexibility to vary prices, subject to the constraint that it does not earn more than a certain amount of total revenue in a given period. This has different effects than a price cap, since a business can meet its revenue cap by adjusting both prices and the quantity supplied.

In theory, **benchmarking techniques** can be used as part of the three regulatory options mentioned above. For example, benchmarking techniques could be used to determine the X parameter for CPI-X price cap regulation, where the benchmark reflects best practice in the industry, or is based on industrywide productivity growth. This would encourage businesses to meet what are seen as desirable yardsticks and reduce the regulator's reliance on detailed information about individual businesses. However, benchmarks might incorporate significant measurement errors or fail to take account of important differences between businesses. If this is the case, then setting prices/revenue on the basis of benchmarking techniques might force efficient businesses to price below their costs, or alternatively allow inefficient businesses to price well above efficient costs.

Even if a regulator had all of the information held by a regulated business, it is unlikely that the regulator (or any other party, including the regulated business itself) would be able to determine precisely the most efficient prices/revenue. Businesses typically have to make decisions under uncertainty, and so regulation of those businesses also involves uncertainty. As noted by the Victorian Essential Services Commission (ESC):

> Regulators seek to overcome the information asymmetry problem by gathering information about the businesses they regulate. These efforts are costly for the both the regulator and the regulated business. The information asymmetry and inherent difficulty of identifying efficient behaviour also implies that regulatory decisions are unable to flawlessly mimic competitive market outcomes; there will be regulatory errors, sometimes favouring regulated businesses and at other times favouring service users. (sub. DR112, p. 7)

Building block approach and reference tariffs

The Gas Access Regime is a form of cost-based price regulation using what is known as the 'building block' approach. In particular, a target is calculated for *expected* total revenue by building up the cost base from its individual components. This requires, among other things, forecasts of future capital expenditure, operating costs and demand. The expected total revenue target is then used to set regulated prices — termed reference tariffs — for individual reference services (services specified in an access arrangement with an associated reference tariff) (figure 7.1).

Each reference tariff generally has to be set so as to recover the costs expected to be incurred in providing the relevant reference service, as reflected in the composition of target revenue (s.8.38). A portion of target revenue might be attributable to services that are not reference services and so do not have an associated reference tariff. Hence, joint costs — including the large portion attributable to capital — have to be allocated between regulated and unregulated services. The Australian Pipeline Industry Association (APIA) argued that taking the additional step of allocating costs between different reference services was undesirable:

> … limiting cost allocation requirements under the Gas Code to the issue of cost allocation between the regulated and unregulated business would be a significant step in limiting the impact of regulator imposed information requirements on the day to day operations of the service provider. (sub. DR100, p. 57)

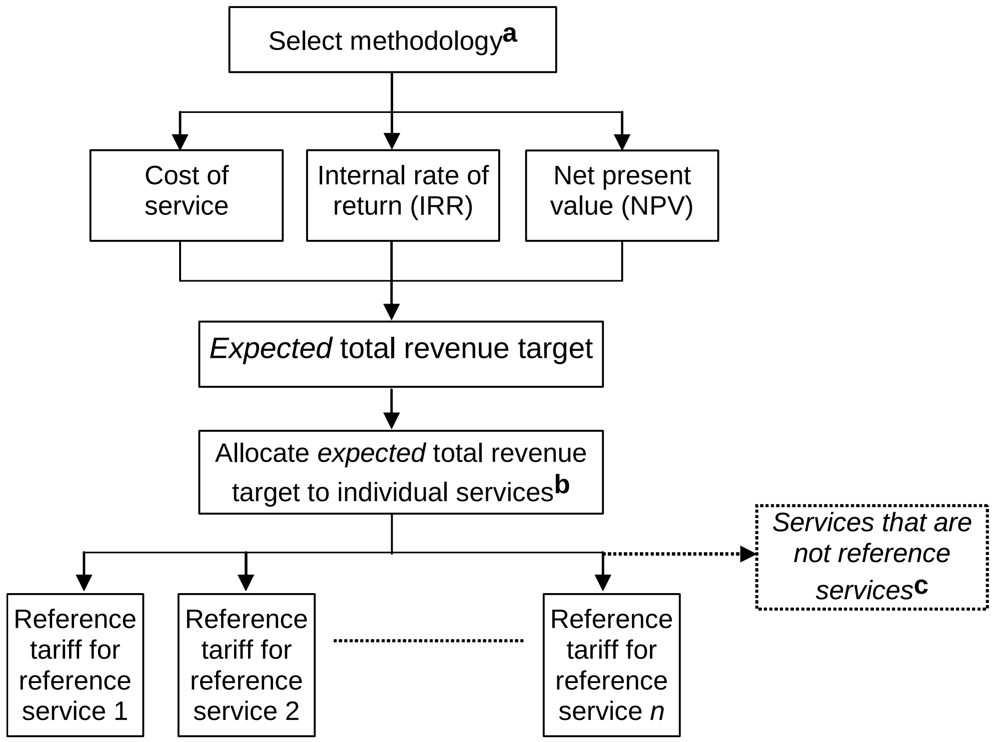
Reference tariffs are intended to be a reference point against which service providers and users can negotiate market-based outcomes:

> The reference tariff serves as a benchmark price at which a prospective user is entitled to gain access to services and applies only to the reference service as defined in the access arrangement. … the [Gas] Code explicitly preserves the right of service

providers and users to enter into negotiated contractual arrangements. Similarly, tariffs can be negotiated if the service required by the user is different to the reference service. (ACCC 2002a, p. 21)

However, as noted in chapter 3, the Gas Access Regime's building block approach has tended to inhibit commercial negotiations.

Figure 7.1 **Determination of reference tariffs**



[a] Methods other than the three shown in the diagram can be used, but only if the resulting total revenue target can be expressed in terms of one of the three methods. [b] The portion of total revenue that a reference tariff recovers for a particular service should generally be attributable to the costs of providing that service (including costs incurred jointly with other services) (s.8.38). [c] Part of the revenue target might be attributable to services that are not specified in the access arrangement with an associated reference tariff.

Source: Gas Code.

Changes in reference tariffs between cost-based reviews

Between (cost-based) access arrangement reviews, service providers have the discretion to determine how their reference tariffs vary (s.8.3), provided:

- the regulator is satisfied that the general principles for reference tariffs (s.8.1) are met
- reference tariffs only vary in accordance with an 'approved reference tariff variation method' specified in a service provider's access arrangement (s.8.3A).

Section 8.3 of the Gas Code lists various possible reference tariff variation methods (box 7.3). One of these is a form of cost of service regulation in which reference tariffs are continuously adjusted over time to ensure that reference tariffs recover the actual costs of providing reference services (termed a 'cost of service approach' in s.8.3(a) and defined in s.10.8 of the Gas Code).

Box 7.3 **Examples of reference tariff variation methods**

Section 8.3 of the Gas Code lists the following examples of how reference tariffs could be varied during an access arrangement period (the examples are defined in s.10.8 of the Gas Code). The Gas Code also mentions that any variation or combination of these approaches could be used.

Cost of service approach — initial reference tariffs are set on the basis of the anticipated costs of providing the reference services and are adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the reference tariffs recover the actual costs of providing the reference services.

Price path approach — reference tariffs are determined in advance for the access arrangement period to follow a path or paths over time forecast to deliver a revenue stream, with that price path or paths not being adjusted to account for subsequent events until the commencement of the next access arrangement period.

Reference tariff control formula — an initial set of reference tariffs may vary over the access arrangement period in accordance with a specified formula or process.

Trigger event adjustment — reference tariffs are varied in the manner specified in a reference tariff policy upon the occurrence of a specified event.

The reference tariff variation method typically used between cost-based access arrangement reviews involves a CPI-X price (growth) cap. Under this approach, the regulator can require reference tariffs to grow at less than the rate of inflation. In particular, reference tariffs are only allowed to grow at a rate of CPI-X per cent. CPI is the consumer price index and is used to adjust for inflation. The value of X is based, among other things, on an assessment of how far the service provider can reduce its future costs:

> The building block approach [used] in determining the X parameter in the CPI-X [price growth] caps uses forward looking efficient costs (as actual costs may reflect past inefficiencies of the regulated business's business) and a benchmark rate of return. (Willett 2003, p. 13)

It could be argued that the CPI is not an appropriate inflation measure to use in a price cap because it measures consumer prices rather than those faced by a regulated business. It seems that a producer price index would be more appropriate. It would also be more consistent with the current practice of using X parameters in price caps which are specific to the service provider or its industry. However, the timely availability of the CPI (and its broad acceptance among regulators, service providers and users) might outweigh any benefits from using an input price index for a service provider or its industry.

The X parameter used in a CPI-X price cap is usually maintained until the next (cost-based) access arrangement review, regardless of whether actual and forecast costs differ. Thus, in the interim, it is possible for:

- actual revenue to exceed target revenue if sales are greater than forecast
- the actual rate of return to exceed the target rate of return (implicit in the revenue target) if costs are less than forecast and/or sales are greater than expected (assuming there are economies of scale).

The Australian Competition and Consumer Commission (ACCC) viewed this as a desirable feature of price caps:

> If the regulated business is able to outperform its benchmark rate of return it can keep the excess revenue and vice versa. This provides strong incentives for service providers to cut costs and improve efficiency. (Willett 2003, p.13)

The use of price caps that, in the short term, decouple reference tariffs from a service provider's costs has led some to describe the regime as 'incentive regulation'. However, the incentive properties attributed to the regime could be overstated. Regulators can require a high proportion of the benefits of above forecast sales and below forecast costs to be passed on to users as lower reference tariffs. This redistribution could occur soon after the benefits occur if a service provider is required to have a 'benefit sharing' mechanism (chapter 9). In addition, there is scope to apply the regime as a form of cost of service regulation — the antithesis of incentive regulation — via either:

- a cost of service reference tariff variation method under s.8.3(a) of the Gas Code
- a benefit sharing mechanism under s.8.46 of the Gas Code that redistributes most, if not all, efficiency gains to users.

Given the regime's flexibility about how price regulation is implemented, its incentive properties depend very much on how it is applied. As noted, the regime has typically involved a cost-based review of tariffs followed by a period of price cap regulation until the next cost-based review. However, the implementation of price caps varies between service providers.

In Victoria, price caps are applied to a weighted average of reference tariffs offered by a service provider, rather than to each individual reference tariff. This approach has been approved by the ACCC for transmission (GasNet) and by the ESC for distribution (Envestra, Multinet and TXU Australia). The Victorian Department of Infrastructure noted:

> The Victorian gas distributors' prices are controlled by a 'tariff basket' control, which caps only the *weighted average* price and provides the distributors with flexibility about how they design their individual prices. Multi part pricing and congestion pricing is not precluded (subject to meeting the overall cap) — indeed, the Victorian Essential Services Commission promoted the 'tariff basket' form of price control because it provides incentives for regulated entities to adopt efficient price structures. (sub. DR104, p. 13)

In contrast, transmission pipelines outside Victoria often have only one reference service and so a price cap can only be applied to a single reference tariff.

The Commission considers that, when there is more than one reference service, it is desirable to apply a price cap to the weighted average reference tariff, rather than to each individual reference tariff. This would enable service providers to adopt more efficient pricing strategies than otherwise.

The Gas Code's flexibility also provides scope for the adoption of other regulatory tools. These tools have to some extent been adopted by service providers and regulators. As noted by the ESC (sub. DR112, p. 16), they include:

- inter-plan sharing provisions (refer to chapter 9 discussion of efficiency carryover mechanisms approved by the ACCC (2002b) and ESC (2002b))
- earnings and revenue sharing mechanisms (refer to the related discussion of benefit sharing in chapter 9)
- trigger mechanisms and off-ramp provisions (refer to chapter 9 discussion of how access arrangement revisions can be submitted prior to a scheduled review).

Redistribution of efficiency gains

Expected future efficiency gains[1] are often incorporated into reference tariffs (as tariff reductions) when tariffs are revised at a (cost-based) access arrangement review. In addition, unexpected efficiency gains can be redistributed to users before the next access arrangement review if the service provider has a benefit sharing mechanism (chapter 9). Various parties expressed concerns that benefit sharing mechanisms apply to only cost reductions in excess of those forecast. Envestra claimed:

[1] The term 'efficiency gain' is used here to refer to a reduction in average cost resulting from greater gas throughput and/or improvements in operating practices.

> … the mechanisms used by regulators are flawed as:
>
> (i) regulated businesses do not receive any of the benefits of gains made to achieve the regulator's imposed productivity improvement; and
>
> (ii) even if the business outperforms the regulator's benchmark, the proportion of gains appropriated are only 30 per cent. (sub. 22, p. 38)

Similar concerns were expressed as follows:

> Under the current approach adopted by Australian regulatory authorities … potential efficiency gains are effectively passed through (in the form of lower regulated tariffs) to end consumers as they are *estimated* to occur. Under this approach service providers do not share in the benefits of efficiency gains achieved, only those efficiency gains made in excess of gains estimated to be possible by regulatory authorities. (AGA, sub. 13, p. 55)

> Although regulators have introduced revenue sharing mechanisms in recent determinations, service providers are still deprived of the necessary returns required to fully mitigate the losses associated with early stage project developments. This issue stems from the common perception that all profits above the economically-efficient level must be monopolistic profits. Pure monopolistic profits should be separated from the 'blue sky' returns associated with a successful investment. (Duke Energy International, sub. 21, p. 10)

> … regulated prices set on the basis of regulator estimates of 'efficient' costs leave investors uncertain as to whether prices will allow recovery of genuine costs for an efficient operator. In addition, by setting prices on the basis of regulator estimates of forward-looking 'efficient' costs, regulators are awarding 100 per cent of what they consider to be achievable efficiencies to customers. Investors get no share in them at all. If regulators over-estimate the potential for efficiencies, then they will transfer to customers the benefits of efficiencies that cannot reasonably be realised. In this case, the share to the investor is negative … Proper incentive regulation requires that only realised efficiencies be shared, and a commitment up front as to how they will be shared. (AGL, sub. 32, p. 37)

The extent to which efficiency gains are redistributed is evident from data supplied by the AGA and reproduced here in table 7.1.

The AGA recommended changes be made so that only actual efficiency gains are eligible to be shared between service providers and users, rather than the current approach of sharing forecast gains. It claimed:

> … there is significant risk of regulatory error in forecasting potential future efficiencies achievable by complex commercial entities. (sub. 13, p. 55)

Table 7.1 **Treatment of efficiency gains by regulated gas businesses**

Jurisdictional regulator	*Treatment of forecast efficiency gains*	*Net present value sharing of forecast gains (business/ user)*	*Treatment of unforecast efficiency gains*	*Net present value sharing of unforecast gains (business/ user)*	*Inter-period efficiency carryover mechanism*
Commonwealth	Not retained	0/100	Retain minimum five years	30/70	Yes
Victoria	Not retained	0/100	Retain minimum five years	30/70	Yes
New South Wales	Not retained	0/100	Retain until reset	30/70[a]	No
South Australia	Not retained	0/100	Retain ten years	50/50	Yes
Western Australia	Not retained	0/100	Retain until reset	30/70[a]	No
Queensland	Not retained	0/100	Retain until reset	Not defined	No

[a] First year efficiency gains only.

Source: AGA, sub. 13, p. 55.

In order to address concerns about the current approach of redistributing forecast efficiency gains, AGL advocated an 'earnings sharing model':

> The components of an earnings sharing model are:
>
> (a) that a price glide path is set from today's average price to a target average price at the end of the next regulatory period (5 years hence);
>
> (b) the target average price is determined as the price that would (if it applied today to the most recent year's volume sales and given the most recent year's actual costs) result in a rate of return equal to the cost of capital. The difference between today's price and the target price represents efficiencies realised in the last regulatory period.
>
> (c) By gliding from today's price to the target price, efficiencies realised in the last regulatory period are transferred to consumers progressively over the next regulatory period, and investors and consumers share in the benefits of improved efficiency. (sub. 32, p. 15)

Similarly, the Energy Networks Association (ENA, which replaced the AGA) recommended a new section in the Gas Code that:

- only permits the sharing of actual, not anticipated, efficiency gains
- requires that gains be shared at least equally (that is, 50:50 in net present value terms) between the service provider and users over time. (sub. DR85, p. 20)

The Commission notes that in competitive markets at least some of the benefits of productivity improvements tend to be redistributed eventually to customers as lower prices. If a pipeline has market power, then such a redistribution is less likely to occur and this might inhibit more efficient outcomes in upstream and downstream markets. Thus, there appears to be a case for regulators to redistribute at least some of the efficiency gains of such pipelines to users. However, the appropriate timing and extent of redistribution is unclear. This probably needs to be assessed on a case-by-case basis and inevitably involves subjective judgments. The Commission does not endorse a fixed sharing rule for all pipelines, such as the 50:50 ratio suggested by the ENA.

The Commission shares the concerns of some inquiry participants that future efficiency improvements are difficult to forecast. Sharing efficiency gains on an *ex post* basis, as suggested by AGL, therefore has some appeal because it would no longer be necessary to speculate about future productivity growth. However, an *ex post* approach would reduce the current regulatory pressure on service providers with a natural monopoly technology to improve productivity. Application of the regime would become more like traditional cost of service regulation with a 'regulatory lag' between when efficiency improvements occur and when the resulting cost reductions are passed on to users. Therefore, the Commission does not support AGL's proposal.

FINDING 7.1

Redistributing efficiency gains to users on an ex post basis could decrease the scope for regulatory error. However, this might come at the expense of reducing the incentive properties of the current ex ante approach.

7.2 Pricing principles

In the review of the national access regime (PC 2001c), the Productivity Commission argued that pricing principles were required to:

- provide better guidance on how the broad objectives of the regime should be applied in setting more detailed terms and conditions
- provide a measure of certainty for regulated businesses and access seekers
- help address concerns that a regulator's own values will unduly influence decisions on terms and conditions.

In general, these arguments also apply to the Gas Access Regime. That is, pricing principles are needed to provide guidance on how the broad objectives of the regime should be applied in setting reference tariffs, provide greater certainty for regulated businesses and access seekers, and reduce the scope for regulatory risk and error (arising from regulatory discretion).

The Gas Access Regime already includes objectives (in s.8.1 of the Gas Code) that are to guide regulators in approving reference tariffs (box 7.4). In addition, s.2.24 of the Gas Code contains factors that need to be taken into account when approving access arrangements, which include reference tariffs.

Box 7.4 **Guiding principles for setting reference tariffs**

Section 8.1 of the Gas Code states:

> A Reference Tariff and Reference Tariff Policy should 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.

In chapter 5, it was noted that the number of objectives and factors to be taken into account by regulators could be reduced so as to limit conflicts among objectives and the need for regulatory discretion. In light of this, chapter 5 recommended deleting clauses (a) and (d)–(g) of s.2.24.

The Commission also recommended in chapter 5, that the following overarching objects clause should be included in the Gas Access Regime.

> To promote the economically efficient operation and use of, and economically efficient investment in, the services of transmission pipelines and distribution networks, thereby promoting effective competition in upstream and downstream markets.

The principles that guide regulators in approving reference tariffs need to be consistent with the recommended objects clause.

The focus of the recommended objects clause is on promoting economic efficiency. This is directly applicable to access pricing. That is, access prices should promote the economically efficient operation and use of, and investment in, pipelines and networks.

Prices that promote economic efficiency — in the sense of encouraging the best use of existing resources — are generally required to be set equal to short-run marginal cost. However, this will lead to losses if there are increasing returns to scale over the relevant range of output (average costs decline as the volume of gas transported increases). Increasing returns to scale are a common characteristic of gas transmission pipelines and distribution networks (chapter 2). Various pricing methods, such as multi-part pricing, have been suggested as ways to encourage efficiency while ensuring that a business with increasing returns to scale does not make losses (box 7.5).

This section considers what pricing principles are most appropriate for reference tariffs, and whether this requires modifications of the Gas Code's current pricing principles.

Principles recommended for the national access regime

The Commission (PC 2001c) recommended a set of pricing principles in its review of the national access regime (box 7.6). The Commission also noted in its review of the national access regime that its recommended pricing principles should provide guidance for the pricing principles used in industry-specific regimes. It argued that these pricing principles should be incorporated into the national access regime and the Competition Principles Agreement (CPA), for the purpose of assessing the effectiveness of State and Territory access regimes (PC 2001c). In the draft report for this inquiry, the Commission recommended that s.8.1 of the Gas Code be replaced with a set of pricing principles that were almost the same as those the Commission recommended for the national access regime.

Subsequently, the Australian Government released its final response to the Commission's review of the national access regime (Costello 2004). The Australian Government's final response agreed that pricing principles should be included in part IIIA of the *Trade Practices Act 1974* (the national access regime). However, the Australian Government modified the Commission's recommended pricing principles as follows:

- In the opening sentence, the phrase '… in seeking to reduce access prices that are inefficiently high …' was deleted.
- In the principle (a)(i), the term 'across a facility's regulated services' was replaced with 'for a regulated service or services'; the term 'long run' was deleted; and 'access to these services' was replaced with 'access to the regulated service or services'.
- Principle (a)(iii) was deleted.

Box 7.5 **Pricing methods in declining cost industries**

Economic efficiency generally requires price to equal short-run marginal cost (SRMC). At this price, all users are paying a price that at least covers the cost of producing the last unit of the good or service. However, in an industry that exhibits significant economies of scale (and hence declining average costs), marginal cost will be lower than average cost across the relevant range of output. In general, setting a single uniform price at marginal cost would result in the service provider failing to recoup all of its costs. This outcome will not provide adequate incentives for the service provider to undertake efficient investment.

A solution to the problem of service providers failing to recoup their costs is to set a single uniform price equal to average costs. However, this generates an efficiency loss because there are users that value the service more than it costs to produce an additional unit but are priced out of the market (Carlton and Perloff 1994). Once the constraint of a single uniform price is removed, there are other options for recovering costs while encouraging more efficient use of the service. These include:

- **Multi-part pricing** — the service provider charges a fixed amount for access to the network, plus a charge for each unit used based on SRMC. So long as the fixed charge does not deter potential users, or reduce demand for the service, this approach will allow the service provider to cover its full costs while providing the correct incentives for users of the service.
- **Ramsey pricing** — charging different users a different amount, such that those users with higher willingness to pay contribute more to funding costs. In this way, total costs will be recouped and users that are willing to pay the costs of producing the last few units will not be priced out of the market.

Allowing Ramsey pricing does raise the possibility that a service provider might use it in an anticompetitive way. That is, a service provider can price in order to disadvantage competitors of its associated businesses in upstream and downstream markets. In addition, while Ramsey pricing encourages efficiency it can also generate concerns regarding equity.

It is conceivable that, over the life of an asset, costs could (eventually) be recovered by SRMC pricing. Although SRMC is initially below average cost, when all capacity is utilised, rationing of the service will cause SRMC to rise above average cost. This occurs because SRMC includes opportunity costs. Thus, where there is a capacity constraint, the opportunity cost of providing access to one customer is the value placed on the service by the customer who misses out. When SRMC exceeds average cost, prices will begin to recover capital costs and signal that new investment is required. However, such an approach is rarely, if ever, employed for infrastructure pricing. Many infrastructure assets are long-lived and SRMC pricing would mean losses for many years with no certainty of ever covering costs. In addition, such an approach would entail significant spikes in prices as facilities became capacity constrained, followed by sharp drops in prices following investment in new capacity. Paradoxically, such price fluctuations might not send the correct signals to consumers about the efficient use of the service over time.

Box 7.6 Recommended pricing principles for national access regime

In its review of the national access regime, the Commission (PC 2001c) recommended that part IIIA of the *Trade Practices Act 1974* should include the following pricing principles:

> The Australian Competition and Consumer Commission, in seeking to reduce access prices that are inefficiently high, must also have regard to the following principles:
>
> (a) that regulated access prices should:
>
> (i) be set so as to generate expected revenue across a facility's regulated services that is at least sufficient to meet the efficient long-run costs of providing access to these services;
>
> (ii) include a return on investment commensurate with the regulatory and commercial risks involved;
>
> (iii) generate revenue from each service that at least covers the directly attributable or incremental costs of providing the service.
>
> (b) that the access price structures should:
>
> (i) allow multi-part pricing and price discrimination when it aids efficiency;
>
> (ii) not allow a vertically integrated access provider to set terms and conditions that discriminate in favour of its downstream operations, except to the extent that the cost of providing access to other operators is higher.
>
> (c) that access pricing regimes should provide incentives to reduce costs or otherwise improve productivity.

Source: PC 2001c.

The main reasons for the Australian Government's changes were that:

- the cost-based access pricing principles set out in (a)(i) and (a)(iii) of the Commission's recommended pricing principles would require a more intrusive and complex regulatory approach
- scope for regulators to use alternative regulatory approaches would be restricted.

The Australian Government's final response also noted that the CPA should refer to the pricing principles in the national access regime for the purpose of assessing the effectiveness of State and Territory access regimes. In addition, the Australian Government observed that the pricing principles in existing access codes were consistent with the principles proposed for the national access regime:

> To achieve consistency in all three access routes under part IIIA [the national access regime], it would be desirable to introduce the same pricing principles into the CPA for the purposes of assessing certification applications. Therefore, the Australian Government will work with participating jurisdictions to include in the CPA a principle to have regard to the above pricing principles for part IIIA …
>
> The above pricing principles for part IIIA are consistent with the pricing principles under existing access codes … While the pricing principles [proposed for the national

> access regime] provide broad guidance on the approach to be taken by decision-makers, an industry-specific regime may include principles which address the individual characteristics of its regulated market. (Costello 2004, pp. 5–6)

Pricing principles suggested by participants

As noted above, in the draft report for this inquiry, the Commission recommended that s.8.1 of the Gas Code be replaced with a set of pricing principles that were similar to those the Commission had recommended for the national access regime.

Participants had a range of responses to the proposed amendment. While some participants supported the amendment, a number expressed concerns regarding specific pricing principles. Through the course of the inquiry, participants also suggested other pricing principles.

The Economic Regulation Authority (ERA, which has assumed the responsibilities of the former Office of Gas Access Regulation, OffGAR) noted that the Commission's introductory sentence in its proposed pricing principles had shifted the emphasis in s.8.1 from principles that should be considered when designing reference tariffs to those the regulator must have regard to in approving reference tariffs. It argued that this could 'reduce the ambit of the force of s.8.1' (trans., p. 982) and increase the scope for disputation:

> … the proposed wording more clearly states the matters of relevance to the relevant regulator and reduces possible ambiguity in this regard. As a practical consideration in reducing the scope for dispute over the design of proposed access arrangements, those preparing such proposals should however continue to also understand that under the [Gas] Code they are under a similar clear and unambiguous obligation. (ERA, sub. DR116, pp. 6–7)

The Commission agrees with ERA's argument that the introductory sentence to the pricing principles be clear that the principles apply to service providers in designing reference tariffs as well as regulators in approving reference tariffs.

The ERA also noted that the proposed pricing principles:

> … no longer makes provision for the relevant regulator to determine the manner in which the proposed objectives can best be reconciled or which of them should prevail. The reason for this omission is unclear, however, presumably the Relevant Regulator would be guided by the objects clause in reconciling any tension between the recommended objectives. (sub. DR116, p. 7)

A number of participants expressed concern regarding the Commission's proposed deletion of s.8.1(b) (replicating the outcome of a competitive market). BHP Billiton considered this objective was important for consumers' interests because:

> This section [8.1(b)] is based on the efficiency 'outcomes' that are contained in the overarching 'objects clause'. It does not assume that the structure of a competitive market should be achieved, or that the outcomes of a 'perfectly competitive market' should be replicated. Consumers will be interested in replicating the outcome of a competitive market, but monopoly service providers will not. (sub. DR96, p. 42)

The ENA (representing service providers) was also opposed to the deletion of s.8.1(b) of the existing Gas Code. It argued that the August 2002 judgment by the Supreme Court of Western Australia regarding the Dampier–Bunbury pipeline (*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231) had provided important guidance on s.8.1(b), and so its deletion would not necessarily improve the quality of regulation:

> Section 8.1(b) has been subject to detailed consideration in the WA Epic Energy case, and its interpretation was a core element of the judgment. … ENA considers that the outcomes of the Epic Energy case reinforce and complement the broad thrust of the reforms proposed by the Commission.
>
> … ENA considers that it is important that the Productivity Commission not recommend the deletion of Section 8.1(b) unless it is certain that this will improve the quality of regulation and not have the unintended consequence of leaving regulatory authorities with less guidance from existing judicial precedents. (sub. DR85, p. 18)

During the inquiry, there was significant debate on how regulators had, and should, interpret the objective of 'replicating the outcome of a competitive market'. The AGA asserted that a competitive market had been interpreted by regulators as a perfectly competitive market:

> Since the introduction of the regime, regulatory authorities generally adopted an approach to applying the national Gas Code which effectively sought to replicate outcomes of theoretically perfect competitive markets — incorrectly interpreting into the national Gas Code an implication that allowable revenue from access prices should be 'just sufficient to ensure continued service provision'. (sub. 13, p. 23)

However, the ACCC disputed this view, noting:

> The notion of perfect competition is, on my view, totally irrelevant to the polar extreme of dealing with a natural monopoly, where you have a decreasing cost curve and a concept of a problem of applying the generally efficient outcome of pricing at marginal costs to be not viable for the infrastructure owner because they don't recover capital costs. …
>
> That's not the approach we take either and it's got nothing to do with those sorts of theoretical constructs. Marginal revenue equal to marginal cost have nothing to do with what we do. What we do is more akin to an average cost approach, recognising that infrastructure owners should have the opportunity and incentive to do better than average costs during a regulatory period in order to pursue efficiency and increase the utilisation of pipeline. (trans., p. 709)

The judgment of the Supreme Court of Western Australia regarding the Dampier–Bunbury pipeline was that a competitive market should be interpreted as a workably competitive market:

> While the evidence of the three witnesses differed in some respects, I am left with the clear impression that in the field of competition policy, especially market regulation, the prevailing view and usage among economists is that a reference to a competitive market is to a workably competitive market. (para. 124, p. 58)
>
> The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period. (para. 128, p. 60) (*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231)

Although the Supreme Court of Western Australia found that it is the prevailing view of economists that a reference to a competitive market is to a workably competitive market, this finding was based on the evidence of witnesses that appeared before the Court and therefore it might not necessarily be economists' prevailing view. Nevertheless, a number of participants endorsed the finding that regulators should interpret a competitive market in accordance with the workably competitive model. Enertrade (sub. 14), for example, noted the workably competitive model was more realistic if an industry is capital intensive.

The concept of workable competition was developed by Clark (1940) at a time when economists had come to recognise there were few markets that met the conditions for perfect competition, but there were competitive markets in which the outcomes were broadly acceptable. Darryl Biggar noted:

> Clark's concern was to articulate a competition standard which could include those industries for which competition was sufficient to yield broadly acceptable outcomes. A useful standard would have several benefits — it would prevent inappropriate intervention in those markets for which outcomes were already adequate and it would provide a target for policy aimed at fostering competition in those markets for which competition was not adequate. (ACCC, sub. 48, attachment 1, p. 116)

Sosnick (1958) formulated a framework for judging whether a market was workably competitive that involved three factors — structure, conduct and performance. The basis of much of the policy application of workable competition that followed Sosnick's framework was that intervention in market structure (for example, disallowing mergers) or prohibiting certain market conduct (for example, predatory pricing) would create an appropriate environment for competition, thereby improving performance (Hay and Morris 1987). The concept was noted by Professor David Round:

> The hallmark of a workably competitive market is flexibility and independence in decision making, with no coercion, and freedom to choose on the part of both producers and consumers. Should these competitive <u>processes</u> be present, the market

will exhibit the desired static and dynamic efficiency characteristics that will maximise social well being, albeit perhaps not in some absolute sense that can be measured against an objective measurement yardstick. (Allgas Energy, sub. 69, attachment 1, p. 7)

However, Hay and Morris (1987) noted the difficulties in implementing this approach:

The difficulty is that we simply do not know enough about the structure-behaviour-performance link to be certain that performance will indeed improve. So the alternative is to intervene directly on performance, and particularly on prices and profits. (Hay and Morris, 1987, p. 569)

The judgment by the Supreme Court of Western Australia identified the possible problem in applying a concept used to create an environment in which competition can develop, to price regulation of a monopoly. The Court also noted that applying this concept would require the application of economic methods and theory:

In s 8.1(b) of the [Gas] Code the stated objective is replicating the outcome of a competitive market in the context of the determination of a reference tariff or the development of a reference tariff policy for a natural gas pipeline. While the underlying notion of a competitive market would appear to be the same in this context as in the preamble to the [Gas Pipelines Access] Act and the introduction to the Code, the precise focus of s 8.1(b) is quite different from the context of the preamble and the introduction. What is in contemplation in s 8.1(b) is a competitive market in the field of gas transportation. The objective is to replicate what would be the outcome if there was competition for the transportation of gas by the pipeline in question, even though it is the premise of the Act and the Code that the pipeline is in a monopoly situation and it would be uneconomic to construct another. The objective seems to necessitate the application of economic methods and theory, albeit to replicate the outcome of a workably competitive market, because the achievement of competition in fact is not possible. (para. 127, *Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231)

While the Court acknowledged that it was the role of the regulator to determine the implications of this for the application of s.8.1(b), it attempted to define some characteristics of a workably competitive market:

… an economist’s understanding of a workably competitive market, is not a fixed and immutable condition with any absolute or precise qualities, but a process which involves rivalrous market behaviour … As such, a workably competitive market will react over time and according to the nature and degree of various forces that are happening within the market. There may well be a degree of tolerance of changing pressures or unusual circumstances before there is a market reaction. The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period. (para. 128, *Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231)

Advice provided to the ACCC by Darryl Biggar concluded that the concept of workable competition lacked precision and provided little guidance to regulators:

> Workable competition, like its cousin ‘effective competition’, is not a precise concept or a term of art but simply denotes that state of competition, which yields broadly acceptable outcomes … (ACCC, sub. 48, attachment 1, p. 115)
>
> … the notion that regulatory decision-makers should regulate in such a way as to replicate the outcomes of a ‘workably competitive’ market is equivalent to saying that regulatory policy-makers should pursue broadly acceptable outcomes. I conclude that the Court’s interpretation of ‘competitive market’ as ‘a workably competitive market’ does not, in itself, provided significant guidance to regulators. (ACCC, sub. 48, attachment, p. 106)

Advice provided to Allgas Energy by Professor David Round, which supported the use of workable competition, also noted that the concept of workable competition lacked precision and might lead to greater regulatory uncertainty in the short term:

> A problem with using workable competition as a regulatory objective, as already noted, is that there is no simple objective formula that uniquely defines its individual dimensions or outer boundaries. Nor can its various characteristics be uniquely weighted to come up with an overall index of competitive health. The notion of workable competition is, rather, a guiding philosophy rather than a precise prescription, as was noted by the WASC [Western Australian Supreme Court]. …
>
> Use of a workably competitive framework as the goal of regulation might well entail less regulatory certainty, at least in the short run, both within and between various regulatory authorities, in terms of precedent and the ability to predict precise regulatory outcomes. (Allgas Energy, sub. 69, attachment 1, p. 9)

However, Professor David Round argued that there would be long-term gains in terms of better regulatory decisions and that regulated businesses would be able to manage this uncertainty as they would be in control of the regulatory process (Allgas Energy, sub. 69, attachment 1).

In addition, Allgas Energy (sub. 69) considered that while the outcomes of replicating a workably competitive market would not be fixed or precise the objectives of workable competition are a clear guide to regulators. It also argued that its price–service offerings were consistent with these objectives.

While some participants supported the idea that prices should be set to include a rate of return on capital that is commensurate (or at least commensurate) with the regulatory and commercial risk involved (AGL, sub. 32; AGA, sub. 13; Northern Territory Treasury, sub. 41; Duke Energy International, sub. 21), others considered this was inappropriate because, for example:

- it is overly restrictive because service providers might have other risks (Worsley Alumina, sub. DR110, p. 16)

- it is unnecessary because regulators already take these risks into account (BHP Billiton, sub. DR96, p. 42).

In addition, the ERA (sub. DR116, p. 8) considered that if this principle was included in the pricing principles for the Gas Code, ‘regulatory and commercial risk’ should be defined to reduce scope for disputation and reduce uncertainty.

Some participants supported the Commission’s draft recommendation that regulated prices should be set ‘to recover at least the long-run efficient costs’ of providing access (especially in the context of the building block approach). AGL noted the term ‘long run’ had been deleted in the Australian Government’s final response to the review of the national access regime and that this was of concern:

> … removal of this reference [to long run in the pricing principles] exposes service providers under the Gas Access Regime to the imposition of short-run marginal cost pricing, which would create uncertainty regarding potential to recoup investments and thus reduce investment incentives. (sub. DR84, p. 16)

However, some participants — such as Western Power (sub. DR115) — were concerned that the term ‘at least’ in principle (a)(i) set no upper bound for revenue. The Energy Markets Reform Forum, Electricity Consumers Coalition of South Australia and Energy Consumers Coalition of Victoria (sub. DR94, p. 49) claimed this effectively ‘leaves an unlimited ability to allow extraction of monopoly rents’.

The AGA (sub. 13) and AGL (sub. 32) were of the view that regulators should allow multi-part tariffs and price discrimination; and prevent cross-subsidies and pricing in favour of associates in upstream or downstream markets. The ACCC also endorsed the principle of price discrimination, noting:

> It is widely accepted that price discrimination among shippers may increase economic efficiency through increased network utilisation. This will particularly be the case for pipelines that are significantly under-utilised. Consistent with this the Australian [Gas] Code [s.8.43] explicitly provides for prudent discounts to be offered by shippers. (ACCC 2002a, p. 22)

In contrast, Duke Energy International (sub. 21) and APIA (sub. 44) claimed that prices should be nondiscriminatory. That is, all users of a given service offering should have access to that service at the same price irrespective of their demand characteristics (in particular, the volume purchased). Duke Energy International also noted:

> … that not only does its NDAP [Nondiscriminatory Access Policy] provide the necessary market supporting mechanisms, it also provides a system which removes the ability of a pipeline to misuse its market power in the event such power is ever realised. This protection comes about through the commitment to nondiscriminatory tariffs. (sub. 21, p. 23)

BHP Billiton also questioned the efficiency benefits of price discrimination, given that gas is sold to final customers through retailers:

> … 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. (sub. 26, p. 91)

BHP Billiton was also concerned that the combined effect of the Commission's pricing principles (a)(iii), (b)(i) and (b)(iii) would be to:

> … provide vertically integrated companies with the flexibility and incentive to move away from tariffs that reflect user-pays on a fully distributed costed basis to a structure that is designed to over-recover and under-recover from various customers within segments. The PC's draft recommendation … would conflict with existing sections (8.38–8.44) and of the [Gas] Code, which allow for differential allocation of revenue (costs) between services and allow for prudent discounts according to the tests of being both 'efficient' and ' fair and reasonable'. (sub. DR96, p. 44)

Participants also suggested that reference tariffs should be set in order to ensure 'financial capital maintenance' (APIA, sub. 44; Enertrade, sub. 14; Duke Energy International, sub. 21). APIA described this principle as follows:

> Generally, an investor would not invest in a firm if it could not expect to recoup the amount invested, that is to maintain capital intact. This is referred to as the financial capital maintenance principle and is a critical driver of the firm's future investment decisions. It follows from the financial capital maintenance principle that regulated businesses should be allowed to maintain intact the financial capital of their investors. This does not mean that a firm should be guaranteed a particular return; rather, there must be a reasonable expectation that the full value of investments will be recouped and expenditure undertaken by the regulated business will be recovered, including where there is a service obligation.
>
> Regulatory decisions that do not accord with this principle, such as by adjusting asset valuations *ex post*, are a form of regulatory taking and must adversely affect incentives to undertake socially desirable investment. (sub. 44, pp. 84–5)

Some participants claimed the arms-length prices established under foundation contracts should act as the floor for the regulated prices of transmission pipelines (Enertrade, sub. 14; Duke Energy International, sub. 21; APIA, sub. 44). Duke Energy International (sub. 21, p. 31) claimed that foundation contract prices were appropriate benchmarks as they are a 'commercially-negotiated and market-based price'. Other negotiated contract prices, or those set by governments' agreements, were also regarded as potential benchmarks for setting prices.

The Commission's assessment

In assessing what pricing principles are appropriate for the Gas Access Regime, the Commission has considered participants' views and the Australian Government's final response to the review of the national access regime.

It is inappropriate for pricing principles to mandate that regulators set prices based on the concept of 'financial capital maintenance'. This is consistent with the view taken in the Commission's review of the national access regime (PC 2001c). In that review, the Commission noted that the principle of financial capital maintenance could be interpreted in two ways:

- The risk that regulators will not allow the service provider to recoup the full investment should, like other risks, be compensated for in the regulatory rate of return.
- That *ex post* reductions (optimisations) of asset values should not be undertaken.

The Commission noted that the first interpretation is consistent with the principle that returns to investors should be commensurate with the regulatory risk involved. In relation to the second interpretation, the Commission considered that optimisation of asset values is not always clear cut and therefore pricing principles should not mandate or prohibit optimisation in all cases (PC 2001c).

The potential for regulators to use foundation contract prices as a benchmark (or price cap) for setting regulated prices is limited. While a price cap could be determined as a volume weighted average of all foundation contract prices, this approach could be difficult to implement because:

- regulators would need to ensure the foundation contracts were determined at arms-length
- regulators might not be able to access confidential information on foundation contract prices.

In addition, foundation contracts are used to underwrite the building of a new pipeline and to bear some of the risks. In effect, a foundation contract customer bears these risks by agreeing upfront to pay a price that might exceed the average cost of supply as volumes grow and greater economies of scale are exploited. Therefore, the Commission considers it would be inappropriate for third party users' prices to be set automatically equal to foundation prices.

The Commission maintains the view (endorsed by some participants) that the use of multi-part tariffs and price discrimination should not be excluded (except where it is used to disadvantage competitors of associated businesses in related markets).

These pricing methods can be efficient in industries with decreasing costs as output rises. While the Commission notes the comments of participants that questioned the benefits of price discrimination, it takes the position that, although this form of pricing might not be appropriate in all circumstances, it should not be excluded.

In light of the proposed changes to the national access regime and the CPA to incorporate appropriate pricing principles, it is important that the pricing principles in the Gas Access Regime are consistent with these principles.

The Commission notes the Australian Government's view that pricing principles under existing access codes are consistent with those that might be included in the national access regime. However, the Commission is concerned that there might be inconsistency between the current pricing principles in the Gas Code (s.8.1) relative to the proposed national access regime pricing principles. This inconsistency could arise for a number of possible reasons, including:

- s.8.1 contains principles that are similar, though expressed in a slightly different way, to the proposed national access regime pricing principles. For example, s.8.1(a) states that service providers should earn a stream of revenue that recovers the efficient costs. In contrast, the principles adopted by the Australian Government in its response to the review of the national access regime indicate that the revenue should be at least sufficient to meet efficient costs ((a)(i))
- s.8.1 provides less specific and operational guidance than the proposed national access regime pricing principles. For example, s.8.1(e) of the Gas Code refers to efficiency in the level and structure of reference tariffs but does not state the specific methods that would achieve this objective. Section 8.1 also does not explicitly state that reference tariffs should be set to 'include a return on investment commensurate with the regulatory and commercial risks involved'.

In addition, the Commission does not consider that s.8.1(b) 'replicating the outcome of a competitive market' is an appropriate objective for setting reference tariffs. This objective suggests that it is possible to determine the tariff that would be the outcome of a competitive market and then replicate it. As noted in chapter 4, although regulators can aim to estimate a competitive market's efficient prices, it is unlikely that the estimated prices will actually reflect efficient prices. This is partly a result of the high probability of regulatory error, but is also a result of the fact that competitive markets are dynamic in nature (chapter 4). If the competitive market outcome cannot be estimated then it follows it cannot be replicated.

Further, as noted above there are a wide range of interpretations of a competitive market — such as perfect and workable competition — each delivering a different outcome. The Commission considers that interpreting a competitive market as workable does not make it easier to meet the requirements of s.8.1(b) of the existing

Gas Code. In fact, the workable competition concept is arguably less well defined and harder to operationalise than other interpretations and might add to regulatory uncertainty. While it is appropriate in the context of policies that attempt to create an environment in which competition can be effective (such as prohibiting predatory pricing) it is less suited to the context of price regulation of monopolies.

FINDING 7.2

Replicating the outcome of a competitive market (s.8.1(b) of the Gas Code) is an unachievable objective for setting reference tariffs. Seeking to apply the concept of workable competition does not provide a practical approach to this problem.

Given the abovementioned deficiency of s.8.1(b) and the potential for other elements of s.8.1 to be inconsistent with the proposed national access regime pricing principles, the Commission considers that the pricing principles adopted by the Australian Government in its final response to the review of the national access regime should provide the basis for the pricing principles used in the Gas Access Regime.

As already noted, the Australian Government's final response to the review of the national access regime suggested a number of modifications to the Commission's recommended pricing principles. The changes were aimed at ensuring regulators could adopt more flexible approaches than those suggested by the Commission's principles, such as productivity-based regulation. In keeping with the Australian Government's intention, the Commission considers significant amendments to s.8 of the Gas Code are needed.

The Australian Government's final response proposed two changes to principle (a)(i). First, the deletion of 'long run' in this principle. The Commission acknowledges concerns that deletion of this term could allow, in theory, regulators to set prices for regulated services at short-run marginal cost, creating uncertainty for service providers regarding the potential to recoup investments. This uncertainty could be overcome by referring in the introductory sentence of the pricing principles to the objects clause (which refers to economically efficient investment). Explicit reference to s.2.24, which refers to requirements necessary for the safe and reliable operation of pipeline, would also ensure that reference tariffs are designed to meet these requirements.

Second, the Australian Government proposed that principle (a)(i) be amended so that it did not require an assessment of 'both the costs and the revenue generated by each service, as specified in the PC's principles' (Costello 2004). That is, while the total revenue generated for all regulated services should reflect the total costs of providing these services, it is not necessary for the revenue generated by a particular regulated service to equal the costs of providing this service (unless there is only one regulated service). The Commission agrees that this amendment would allow more flexible regulatory approaches to be used.

In addition, the Commission accepts the Government's concern that principle (a)(iii) could also limit the scope to use more flexible regulatory approaches. In the national access regime inquiry, the Commission (PC 2001c, p. 335) argued that subsidy-free prices are a requirement for efficient pricing outcomes, and agreed with participants — including the ACCC — that cross subsidies between services would be possible without a principle like (a)(iii). However, in the context of the gas transportation industry, the Commission considers that a profit maximising business will have few incentives to price below the incremental cost of supplying a reference service and therefore this principle is not essential.

FINDING 7.3

There would be benefits in replacing the existing reference tariff objectives (s.8.1 of the Gas Code) with the pricing principles that the Australian Government has agreed to adopt for the national access regime. This would provide more specific and operational guidance for setting reference tariffs under the Gas Access Regime and ensure consistency with the national access regime.

RECOMMENDATION 7.1

In order to provide more specific and operational guidance for setting reference tariffs under the Gas Access Regime, and ensure consistency with the national access regime, s.8.1 of the Gas Code should be replaced with the following:

s.8.1 A reference tariff or reference tariff policy should be designed with regard to the overarching objects clause, s.2.24 and the following principles:

- ***(a) that reference tariffs should:***
  - ***(i) be set so as to generate expected revenue for a reference service or services that is at least sufficient to meet the efficient costs of providing access to the reference service or services***
  - ***(ii) include a return on investment commensurate with the regulatory and commercial risks involved***
- ***(b) that reference tariff structures should:***
  - ***(i) allow multi-part pricing and price discrimination when it aids efficiency***
  - ***(ii) not allow a vertically integrated service provider to set terms and conditions that discriminate in favour of its associated businesses in upstream or downstream markets, except to the extent that the cost***

of providing access to non-associates is higher

(c) that reference tariffs should be set so as to provide incentives to reduce costs or otherwise improve productivity.

It is also necessary to delete other parts of s.8 of the Gas Code that could conflict with the Commission's recommended pricing principles:

- The overview in italics at the beginning of s.8 is inconsistent with the recommended pricing principles and increases the potential for misinterpretation of other parts of s.8 (including recommended changes made later in this chapter).
- Section 8.2(c) and s.8.42 imply costs are to be allocated to individual users. This could inhibit efficient price discrimination.
- Section 8.3(a) allows for a cost of service reference tariff variation method between access arrangement reviews. This is inconsistent with part (c) of the recommended pricing principles.
- Section 8.38 requires the allocation of costs between reference services (where there is more than one reference service).
- Sections 8.39–8.41 provide unnecessary detail on how costs are to be allocated.
- Section 8.43 refers to prudent discounts for individual users and with deletion of s.8.42 is no longer necessary.
- Section 8.45 is not required and might limit the adoption of more innovative incentive mechanisms.

RECOMMENDATION 7.2

To ensure there is no conflict with the pricing principles specified in recommendation 7.1, the following should be deleted from the Gas Code:

- ***the overview in italics at the beginning of s.8***
- ***ss8.2(c), 8.3(a), 8.38–8.43 and 8.45.***

In addition, it is also necessary to change other parts of s.8 of the Gas Code:

- Section 8.44 implies that costs should be allocated to individual reference services. This could inhibit more flexible pricing approaches and price discrimination and therefore should be changed to refer to reference tariffs in aggregate.
- Section 8.46 is overly detailed and provides additional objectives for designing references tariffs. It should be simplified to refer only to the overall objectives of the Gas Access Regime and the recommended pricing principles.

RECOMMENDATION 7.3

To ensure there is no conflict with the pricing principles specified in recommendation 7.1, the first paragraph of s.8.44 of the Gas Code should be changed to:

s.8.44 The Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism (an Incentive Mechanism) that permits the Service Provider to retain all, or any share of, any returns to the Service Provider from the sale of Reference Services in aggregate (not individual Reference Services when there is more than one):

And s.8.46 of the Gas Code should be changed to:

s.8.46 The design of an Incentive Mechanism should be consistent with achieving the overall objective of the Gas Access Regime and the pricing principles specified in s.8.1.

7.3 Target revenue methods

The Gas Code (s.8.4) specifies three methods that can be used to determine target revenue (box 7.7 and figure 7.1). There are many technical issues involved in using these methods, such as the appropriate rate of depreciation, how to apportion fixed costs between different services and time periods, the appropriate rate of return on capital, and the value of the capital base. As a result, it is possible to generate a range of values for the revenue target, even using a single method. In other words, the most efficient revenue target cannot be known with certainty.

Implementation by regulators

The possibility that there is a range of plausible values for a total revenue target is recognised in s.8.6 of the Gas Code, which gives regulators discretion in approving reference tariffs. In particular, regulators may have regard to any financial and operational performance indicators they consider relevant in order to determine the level of costs within the range of feasible outcomes that is most consistent with the guiding principles (s.8.1) for reference tariffs.

Box 7.7 **Methods used to calculate total revenue target**

Section 8.4 of the Gas Code specifies that total revenue should be calculated according to one of the three methods described below. Other approaches may be used, but only if the resulting total revenue can be expressed in terms of one of the three specified methods (s.8.5).

1. Cost of service

Total revenue is set equal to the cost of providing all services over the life of an access arrangement. This cost is derived from the value of the capital base at the start of the access arrangement period; the *ex ante* regulatory rate of return on the capital base; depreciation of the capital base; and forecast noncapital costs. The *ex ante* regulatory rate of return must be commensurate with prevailing conditions in the market for funds, and the risk involved in delivering the services specified in the access arrangement.

2. Internal rate of return (IRR)

Total revenue is set to provide an *ex ante* regulatory rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service. This is done by solving for R_k (revenue in each period of the access arrangement) in the following equation:

$$K_0 = \sum_{k=1}^{n} \frac{R_k - C_k}{(1+r)^k} + RV_n$$

where the access arrangement applies for n time periods; K_0 is the capital base at the start of the access arrangement period; R_k (revenue) is a function of forecast demand and prices in period k; C_k is forecast operating and maintenance costs to be incurred in providing services during period k; r is the *ex ante* regulatory rate of return; and RV_n is the residual value of the capital base at the end of the access arrangement period.

3. Net present value (NPV)

Total revenue is set to provide a forecast NPV of zero. This is done by solving for R_k in the following equation:

$$\sum_{k=1}^{n} \frac{R_k - C_k}{(1+r)^k} + RV_n - K_0 = 0$$

where the variables have the same meaning as for the IRR method.

A common view among service providers was that regulators have adopted an unnecessarily restrictive interpretation of the Gas Code:

> Regulators focus on the elimination of economic profits even though this is not an objective of the National Gas Code. (Epic Energy, sub. 37, p. 2)
>
> The current regime creates an environment where regulators maintain a focus on ensuring the removal of monopoly rents. Consequently, this leads regulators to attempt to make precision estimates of efficient costs when there is significant potential for

> getting such estimates wrong. This applies not only to capital and operating costs, but also to the cost of capital. (Australian Pipeline Trust, sub. 55, p. 11)
>
> The current regulatory model, especially the provision that only ‘efficient’ costs shall be recoverable, presumes efficient costs are capable of accurate estimation by the regulator … (AGL, sub. 32, p. 16)
>
> … the pricing methodology in the current [Gas] Code is largely predicated on replicating the theoretical concept of ‘perfect competition’, as opposed to the concept of ‘workable competition’. In practice, perfect competition can be viewed as being an unrealistic assumption. (Duke Energy International, sub. 21, p. 32)

Epic Energy claimed that the Supreme Court of Western Australia had ruled:

> … assessing whether a proposed reference tariff and reference tariff policy complies with section 8 principles does not involve the regulator undertaking calculations producing fixed results and a fixed ‘yes’ or ‘no’ answer, but involves considering whether the proposed reference tariff and reference tariff policy are consistent with the stated ‘principles’ (not prescriptions) — the notion of compliance does not involve a single uniquely correct outcome, but a determination whether the proposal is reasonable within section 8 … (sub. 37, p. 29)

Various participants highlighted two recent appeal decisions by the Australian Competition Tribunal (*Application by Epic Energy South Australia Pty Ltd* (2003) ACompT 5; and *Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6) that found the ACCC had made errors that disadvantaged service providers. With respect to GasNet’s access arrangement, the Australian Competition Tribunal found that:

> GasNet has established to the satisfaction of the Tribunal reviewable error in relation to:
>
> (a) the estimation of the various parameters of the CAPM [capital asset pricing model] used for calculating the Rate of Return on the capital assets which form the GNS [GasNet system] (see par [19]);
>
> (b) the ACCC’s determinations of the values of five non-capital cost parameters (see pars [22]–[23]); and
>
> (c) the ACCC determining for itself a Rate of Return for the purposes of s 8.30 in circumstances where GasNet’s proposed Rate of Return using the CAPM was consistent with the objectives of s 8.1 of the Code (see par [24]). (*Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6, par [60])

Epic Energy expressed concerns about the transparency of the methods used by regulators to set reference tariffs:

> The reluctance of the ACCC and the Western Australian regulator to release the mathematical models which supported the values used in their various decisions, even when most of the information contained in the models was sourced from information provided by the service provider. While the ACCC, in the case of the Moomba to

> Adelaide pipeline system regulatory approval process, was prepared initially to allow representatives from Epic Energy to 'watch over' the ACCC's staff as they took them through a version of the model used to support the draft decision, and eventually provided Epic Energy with an electronic version of the final decision model some 3 months after the decision was handed down (and albeit subject to unnecessary confidentiality constraints), the WA regulator has refused to provide Epic Energy with a copy of the model used for the purposes of the Dampier–Bunbury pipeline Final Decision. (sub. 37, p. 37)

Envestra claimed:

> … regulators act as the consumers' advocate, as well as the judge and jury in the regulatory process. The conflict arising from this dual role has been manifested as a bias in the regulators' office to rely on its own work, or that of consultants, rather than that undertaken by the distribution businesses. (sub. 22, p. 18)

Envestra cited an example where the Queensland Competition Authority decided to use demand forecasts from a consultant to determine the access arrangement for Envestra's Queensland network. The consultant advised that annual growth would be just over 4 per cent, compared to Envestra's proposal of about 2.5 per cent, which it considered challenging. Annual demand growth since the determination has been about 1.5 per cent.

Mr Michael Cavell (Chief Executive Officer of Enertrade) noted that the building block approach is not used as a part of standard practice by pipeline businesses. Rather, it is a peculiarity of the Gas Code. To highlight this point, Mr Cavell mentioned his experience when employed by Duke Energy International:

> … when we built the Eastern Gas Pipeline … we built in 40 per cent extra capacity [above that required by foundation customers] … We did that based on a forecast that we, through our commercial activity, could stimulate demand … When those arguments were presented to the regulator, the first thing they said was, 'Show me the cost of service derivation of your tariff?' Our response was that we did not do a cost of service determination; it was a negotiated outcome. The response was confusion — I think is the best way to put it. They couldn't grasp that we actually came up with a number through the give and take of negotiation. We ran that through economic models that assessed its ability to deliver an acceptable outcome from a commercial standpoint and didn't really focus too much on the derivation of a cost-of-service tariff — because it wasn't relevant to us at that point in time; we were engaged in a commercial process. (Enertrade, trans., pp. 278–9)

However, the ACCC noted:

> … any economic regulation that imposes a requirement for prices to be determined on a fair and reasonable basis will require some level of intrusion into the affairs of business operators. Indeed, for regulation to be effective it must have the effect of modifying the behaviour of firms in the industry. In the case of the pipeline industry once a decision has been made to cover a pipeline, the modified behaviour that is sought will be a

reduction in prices that limits the capacity of the operator to exercise its market power and accumulate monopoly profits. From the perspective of a pipeline operator, any regulatory framework that is effective will be perceived to be intrusive because it will necessarily lower the earning potential of the business.

The Gas Code as currently drafted incorporates a range of mechanisms to ensure that the interests of all parties are given weight and balanced. These requirements ensure that the Code does not interfere with the interests of pipeline operators any more than is required in order to reasonably restrain the exercise of market power. Further, the ACCC's application of the Code can best be characterised as a balancing process. (sub. 48, p. 34)

The ACCC also claimed:

… the risk of regulatory error is largely quarantined to the return on equity component of the rate of return, and within that, constrained primarily to the market risk premium and the equity beta. Approximately 15–20 per cent of total revenue is attributable to the market risk premium and beta. Australian regulators are conscious of this risk and tend to be conservative in their selection of values for the market risk premium and equity beta. (sub. DR101, p. 21)

The ACCC observed that two rating agencies — Moody's and Standard & Poors — viewed Australian regulation as being favourable for service providers:

Moody's has stated it rates Australian utilities more highly than their UK counterparts, even with the same debt coverage ratios, due to its view that Australia's regulatory regime allows more scope to the utility to outperform allowed rates of return. In its two most recent reviews of Australia's utilities, Standard & Poors demonstrates confidence that the regulatory framework provides them with stable and secure cash flow streams, and that any threats to credit ratings are more likely to come from overgearing (to exploit that stability), or a shift into less secure lines of business. (sub. DR101, p. 18)

However, with respect to Moody's assessment, the Network Economics Consulting Group (NECG) noted:

… it has been written from a debtholder's perspective, and hence says little, if anything, about equity. To date, regulators have ensured that firms are able to meet debt obligations, even in the most contentious regulatory decisions. (sub. DR97, p. 35)

The Allen Consulting Group (ACG) compared market valuations of service provider assets with those determined by regulators. It used this comparison to argue that regulatory decisions have tended to favour service providers:

The clear conclusion from the evidence … 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.

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. (BHP Billiton, sub. 26, attachment, p. 60)

However, NECG was critical of the method used by the ACG:

[The] ACG (and the ACCC) fail to recognise that there are a number of reasons why investors may value a firm at greater than its regulatory asset value.

Regulators adopt a range of asset valuation approaches. In particular, they may value an asset at below the depreciated optimised replacement cost (DORC), as was the case with the Western Australian regulator, OffGAR, on the Dampier–Bunbury pipeline and the ACCC with respect to the Moomba–Sydney pipeline. In addition, the DORC value itself may be subject to dispute, as was the case on the Moomba–Adelaide pipeline. Given the wide range of approaches and uncertainty in applying any particular methodology, investors may value the long term earning potential of an asset on a different basis to that actually applied by the regulator. For example, investors may anticipate that a DORC value will become the most appropriate in valuing longer-term cash flows, even though prices are not currently set on that basis. Investors may also consider it possible that the long-term regulatory environment will change in a way that removes current perceived deficiencies. Recent cases where rulings on appeal have rejected some of the most onerous ACCC positions have given some justification for such optimism.

Investors will value the potential to reap economies of scope in unregulated markets, even if opportunities are not present exactly at the time of purchase. Being in the business may create a real option for future investment outside the regulated entity.

… A ratio of the market value to 'regulatory value' of one does not imply that the same ratio on marginal investment is one. An average ratio of more than one does not necessarily mean that the conditions for future investments are favourable as implied by the ACG analysis. In addition, for risky investments one would expect this ratio to be greater than one to the extent that a survivorship bias is present.

Market valuations of any asset are highly volatile. Any estimate of the ratio of market value to regulated value will vary over time. Not only can the value of a stock fluctuate regardless of movements in the overall market, but the market index can vary such that there are periods when the ratio of market value to replacement cost for the market as a whole is above one and periods when it is below one.

> Finally, there are other reasons why investors may value a firm at greater than its regulated value, such as where there are tax benefits or favourable tariff rulings that apply to the purchasers. These factors were present in Victorian and South Australian privatisations of gas and electricity network businesses.
>
> In our opinion the ACG report cited by the ACCC does not provide an adequate basis for any conclusion regarding whether or not the regulatory returns in Australia are higher than required by investors. (NECG, sub. DR97, pp. 33–4)

NECG was also critical of how the ACG applied its method:

> In addition to the conceptual flaws in the measure chosen, the ACG analysis contains a number of sampling and application errors. These include that:
>
> - The sample chosen is selective and biased. ACG ignore the experience of the Australian Pipeline Trust and Epic Energy, the entities that have been subject to the most contentious regulatory decisions in recent years;
> - While ACG have provided a wide range for the value of the retail business, it is not obvious that their ‘upper bound’ figure represents a true ‘upper bound’. In practice energy retailers are rarely sold as a stand-alone entity. Retailers increasingly integrate with generators to manage risk and have typically been sold with distributors. The value placed on a stand-alone retailer will vary depending on the ability to find a buyer with an upstream hedging opportunity. If such a buyer exists it is likely they will have significant bargaining power, resulting in a sale price lower than the sellers valuation;
> - ACG ignores the presence of significant unregulated assets held by businesses. For example, in the case of GasNet, unregulated assets including metering equipment and an LNG facility were included in the sale; and
> - ACG arbitrarily removes Alinta from its sample to provide a range of 1.4 to 1.6. ACG’s own estimates provide a ratio between 0.8 and 1.0 at four points in time. In addition, the market value of Alinta includes an unregulated LPG contract, a point noted by ACG. (sub. DR97, p. 34)

Nevertheless, it is important to recognise the difficult task given to regulators under the Gas Access Regime. As noted above, a range of plausible values could exist for target revenue, given the uncertainty about the many technical economic issues involved. To ensure that regulators understand this and that target revenue is calculated in a way that is consistent with the overall objectives and new pricing principles recommended by the Commission, it is necessary to revise s.8.6. In particular, the current term ‘appropriate value’ could be misinterpreted as implying that there is an optimal value for the rate of return, capital base, depreciation and noncapital costs. The Commission recommends that it be made more explicit that service providers propose the relevant values and regulators assess whether those values are within a plausible range.

RECOMMENDATION 7.4

To ensure the guidance given to regulators is consistent with recommendation 7.1, s.8.6 of the Gas Code should be changed to the following:

s.8.6 In view of the manner in which the Rate of Return, Capital Base, Depreciation Schedule and Non Capital Costs may be determined (in each case involving various discretions), a range of values may be attributed to the Total Revenue described in section 8.4. In order to assess whether a value proposed by a Service Provider is within this range the Relevant Regulator may have regard to any financial and operational performance indicators it considers relevant in order to determine whether the level of costs nominated by the Service Provider is within the range of plausible outcomes under section 8.4 that is consistent with the pricing principles contained in section 8.1.

Constraint on non-building block methods

The ACCC claimed that the Gas Code's building block approach was superior to its main alternative:

> Primarily due to its incentive properties, the building block approach represents a superior approach to its main alternative, rate of return regulation. Accordingly, the building block approach represents an appropriate method to determine the initial access charge which can be rolled forward and possibly used as a base price in conjunction with other pricing options. (sub. 48, p. 36)

Similarly, the ESC viewed the building block approach favourably:

> The building block approach has been shown to be a robust methodology and has provided high-powered incentives to achieve cost efficiencies and to maintain service quality. The incentive mechanisms incorporated into the approach have reduced regulators' informational disadvantage and made the approach less intrusive and information intensive in subsequent access reviews. In addition, by placing relatively more emphasis on revealed cost information, regulators can achieve a more appropriate balance between the legitimate commercial interests of infrastructure operators (in maintaining financially viable operations and having the capacity and incentive to undertake long-term investment) and the legitimate interests of users of infrastructure services in receiving reliable service at efficient prices. (sub. DR112, p. 14)

Nevertheless, service providers and some regulators were concerned that the only option under the Gas Code is cost-based regulation using a building block method. While s.8.5 of the Gas Code states that different methods can be used, the scope to use a different method is effectively removed by a requirement that any such method:

- must involve the derivation of a total revenue target
- the total revenue target must be able to be expressed in terms of one of the three specified methods (cost of service, internal rate of return (IRR), or net present value (NPV)).

The AGA claimed:

> … these restrictions have prevented service providers from proposing access arrangements based on access pricing models that were not cost-based, and prevented regulatory authorities that might support less intrusive forms of access pricing regulation from approving alternative access pricing arrangements. (sub. 13, p. 38)

Duke Energy International similarly claimed:

> Although a service provider has some discretion as to the form of regulation (e.g. cost of service, IRR, NPV), in practice, whichever option is adopted, the price control methodology will ultimately be based on a building block model. What this means is that reference tariffs are set on the basis of a detailed dissection of the service provider's costs. (sub. 21, p. 9)

More generally, service providers tended to be critical about the use of a cost-based approach:

> A major problem with the cost of service approach is that it requires the regulator to make assessments of the efficient costs of the business. This is very difficult and it is likely that the regulator will make an error. (Envestra, sub. 22, p. 24)
>
> Efficient costs are difficult, if not impossible, to determine and any estimate of efficient costs can only be properly expressed as a range which is so wide as to render them of little practical use. (AGL, sub. 32, p. 37)

The ESC expressed reservations about continuing to use the building block approach over the longer term:

> … while the building block model has been effective in the past, the ESC is concerned that it may not be the best regulatory approach going forward. In particular, the problem of information asymmetries remain pronounced under the building block model. Even if the efficiency of past expenditures is 'revealed', the method still requires forecasts of efficient capital and operating expenditures during the price control period. Projecting future costs is an information intensive and inherently uncertain process that is fraught with risk. On the one hand, there is the risk of overcompensating regulated businesses, thereby leading to excessive prices and profits, distorted infrastructure investment and misallocated resources in upstream and downstream markets. On the other hand, there is a risk of providing inadequate prices and revenues for regulated businesses, undermining their financial viability and incentive and capacity to invest. The potential risk of overcompensation is exacerbated by the fact that firms clearly have incentives to 'game' the cost forecasts that are used

> to determine their forward-looking revenues. The information asymmetry between regulators and regulated firms may make it especially difficult for regulators to detect such gaming.
>
> These concerns are one reason the ESC and other Australian regulators have been exploring alternative regulatory options to the building block model. (sub. DR112, p. 14)

The ESC went on to suggest:

> Greater flexibility could be encouraged by modifying section 8 of the Gas Code to allow for a greater range of regulatory methods and mechanisms than the very limited range of regulatory methods that are currently allowed.
>
> The obvious objection to this proposal is that enhanced flexibility will generate greater uncertainty and regulatory risk. This is a legitimate concern, and the [Essential Services] Commission proposes the following safeguards to ensure that discretion is used appropriately.
>
> First, any use of discretion and alternative regulatory methods should not be restricted to regulators and should also be available to regulated companies and other interested parties. One of the companies' main concerns with existing regulatory methods is that nearly all potential use of discretion is in the hands of regulators. … Second, the exercise of regulatory discretion could be limited to situations that contribute to the Code's new overarching objective. Any party (including a regulator) proposing an alternative regulatory approach could be required to demonstrate that its recommended approach will promote greater long-run efficiency compared with existing regulation. This requirement could be made explicit but not be applied overly stringently. It will often not be possible to quantify any efficiency gains associated with a new regulatory method, but the proposing party should at least put forward a compelling conceptual case describing how its method will promote greater long-run efficiency. (sub. DR112, p. 17)

As outlined in chapter 4, the Commission has concerns about cost-based price regulation being a key feature of the regime. Therefore, the Commission considers that s.8.5 of the Gas Code should be amended so that service providers have a genuine option to use a method other than the building block approach. Rather than prescribe the details of new methods in the Gas Code, it should be up to service providers to devise innovative new proposals for assessment by their regulator. Regulators should assess such proposals in the context of the new objects clause recommended in chapter 5.

RECOMMENDATION 7.5

To provide greater flexibility for price regulation than that provided by the current building block approach, s.8.5 of the Gas Code should be replaced with the following:

s.8.5 A Service Provider can use another method to calculate Total Revenue, provided the Relevant Regulator is satisfied that the proposed method is more likely to meet the overall objective of the Gas Access Regime.

Productivity-based regulation as an alternative approach

The ESC noted that the most widely discussed alternative to the building block approach is productivity-based regulation:

> The main regulatory alternative to the building block approach that has been discussed in Australia is productivity-based regulation. (sub. DR112, p. 15)

In principle, there are two ways in which productivity-based regulation can be applied. These are to set the level of a regulated price, and to set the rate of growth of a regulated price.

Setting the level of reference tariffs

In theory, productivity-based regulation could be used to set target revenue on the basis of industrywide benchmarks, rather than a detailed examination of each business's costs. For example, target revenue could be set so as to just recover the costs that would be incurred by a service provider if it adopted industry best practice. The ACCC claimed that it already tends to use this approach to some extent, but it is constrained by the actions of service providers, third parties and others:

> The ACCC's application of the [Gas] Code has tended to be applied with reference to benchmarking of relevant cost data and is complemented by the use of market data where appropriate or required by the Code. This implicitly entails a light-handed approach to regulation. However, service providers, third parties and others contribute to the access arrangement approval process by supplying information and requesting specific costs be recovered or disallowed; collectively these actions may create a perception that the Code is not light-handed. (sub. 48, p. 36)

However, as the Commission (PC 2001c) noted in its review of the national access regime, the setting of access prices cannot be fully decoupled from a business's costs. Doing so creates a risk that efficient businesses will be forced to bear losses due to the use of inappropriate benchmarks. This is possible, for example, when benchmarks incorporate significant measurement errors or fail to take account of important differences between businesses. Similar concerns were expressed by some participants in this inquiry:

> … 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. … It is our view that a benchmark regulation approach would be

unlikely to be appropriate even if sufficient information existed. (BHP Billiton, sub. 26, attachment prepared by the ACG, p. 27)

There are a number of issues that may impact on the feasibility of a benchmarking approach in the future including limited productivity data and the ongoing potential for variation in productivity growth between individual companies. As benchmarking moves away from a firm's own costs there is greater potential for a firm to earn excessive profits or to have insufficient revenue to meet its cost obligations. Either outcome could lead to undesirable outcomes. (ACCC, sub. 48, p. 48)

… economic theory does not suggest that it is always efficient to break the link between regulated prices and the regulated firm's costs entirely. … the greater the 'power' of the incentive scheme on cost savings (i.e., the greater the reliance on exogenous cost measures), the greater the incentive of the regulated firm to cut service quality and the greater the likelihood of large deviations between prices and apparent costs. A regulatory regime under which the regulated firm dramatically cuts service quality or appears to be either exceptionally profitable or making significant losses is not likely to be one which is sustainable in the long run.

This has been recognised in the economics literature for some years. In an article in the Rand Journal of Economics in 1989, entitled 'Good Regulatory Regimes', Richard Schmalensee compares pure 'price cap' regimes (in which prices are set independently of costs) and 'cost based' regimes (in which prices are closely linked to costs). He concludes: 'regimes in which price depends in part on actual cost generally substantially outperform pure price caps, particularly in terms of consumers' surplus'.

… the optimal regulatory approach is likely to be one which places at least some weight on the regulated firm's own costs. This might be through, for example, periodically assessing the profitability of the regulated firm, or through periodically re-adjusting a price cap to bring it into line with revealed costs. In both cases the BBM [building block model] (or some variant) would be used to assess the costs of the regulated firm. Economic theory does not allow us to assert that there should be no connection between a regulated firm's prices and the regulated firm's costs. (ACCC, sub. DR101, appendix D prepared by Darryl Biggar, pp. 8–9)

Broadly, AGL sees greater value in focusing on clearer guidance for regulators in applying the components of the cost-based model to the determination of target revenue, rather than focusing on refinements to benchmarking approaches. AGL considers that benchmarking has some limited usefulness but not as a primary methodology of access regulation. (AGL, sub. DR84, p. 20)

… productivity-based regulation does have certain disadvantages. The biggest such concern is … the possibility that price controls will not track trends in external business conditions that affect a company's costs. Relevant business conditions include weather, the business cycle, prices of competing energy products, and government policy. (Pacific Economics Group, sub. DR113, p. 10)

Given the problems associated with decoupling tariffs from costs, the Commission does not support the use of a productivity-based technique as the primary means of setting the level of a reference tariff. Tariffs still need to be set with some degree of reference to the actual costs of a regulated business.

Setting the growth of reference tariffs

Another option is to use a productivity-based method to set the path of prices from one (cost-based) access arrangement review to the next. For example, the rate of price growth allowed under a price cap could be based on the long-run historical trend in productivity growth. This raises the question of which productivity trend to use. It could be that for the regulated business, its industry, or the economy as a whole.

Setting a price cap on the basis of the regulated business's past productivity growth has the advantage that it is more likely to reflect the unique circumstances of that business. A potential disadvantage is that the regulated business might have had little incentive to increase productivity in the past, and so there needs to be an acceleration from the historical trend.

The ACCC expressed interest in using the economywide trend in productivity to set a price cap for an individual service provider:

> At the Utility Regulators Forum we had a presentation on a particular approach to calculating [the] X [parameter in a CPI-X price cap] in the WA rail regime which tended to rely on TFP [total factor productivity] in the economy as a whole, against a sort of benchmark productivity measure in the long term for rail infrastructure … These sorts of approaches that rely less and less on information provided by a particular service provider and information that's available from the economy as a whole are certainly worth pursuing. (trans., p. 716)

The Commission does not support the use of an economywide productivity measure to set price caps for service providers. It is not sensible to expect the productivity of individual businesses, or even whole industries, to grow at a rate similar to that of the economy as whole. Such an approach would significantly increase the potential for regulatory error.

Pacific Economics Group (PEG) argued that an industry productivity trend should be used to set a price cap. It noted that US regulators have done this because:

> The American approach is based on the premise that utility regulation should mimic the outcome of competitive markets. … In competitive markets, prices change at the same rate as the *industry's* trend in unit costs and are not sensitive to the unit cost trend of any individual firm. (sub. DR113, pp. 4–5)

Reliance on an industry rather than business level trend was nominated by PEG as a distinguishing feature of productivity-based price caps:

> The main difference between a building block and productivity-based approach to setting price changes in CPI-X [price cap] regulation is that the latter is calibrated on the basis of *industry* TFP [total factor productivity] trends and not a company's own expected costs. (sub. DR113, p. 7)

In addition, the use of industry trends was viewed as a way to substantially reduce the compliance cost and contentiousness of regulation:

> Productivity-based regulation can also have a beneficial effect on regulatory compliance cost. The cost and contentiousness of regulatory reviews can be substantially reduced. Unlike the building block approach, reviews can focus on industry TFP [total factor productivity] and input price trends rather than detailed examinations of company costs. (PEG, sub. DR113, p. 8)

However, this assumes that:

- industry cost trends can be calculated in way that is relatively inexpensive and uncontroversial, compared to using the building block approach to calculate the level of a regulated business's costs
- the calculation of industry trends is unlikely to involve large measurement errors
- the historical trend in productivity will be replicated in the future; or regulators can use relatively inexpensive and uncontroversial quantitative techniques to adjust past trends so they take account of future determinants of productivity growth
- individual businesses are sufficiently homogeneous that they can increase productivity at a similar rate to the industry as a whole; or regulators can use relatively inexpensive and uncontroversial quantitative techniques to account for business heterogeneity.

The Commission is not convinced that these conditions will necessarily apply for Australian natural gas pipelines. The use of industry productivity trends could be far more contentious and costly than asserted by the supporters of productivity-based regulation. Potential issues to be resolved include:

- What procedures are to be used to aggregate business level trends into an industry level trend? If the industry trend is calculated as a weighted average of the productivity growth of individual businesses, what are the appropriate weights to use?
- How will inconsistent accounting methods between businesses, such as for depreciation and the cost of capital, be reconciled? Capital costs account for a substantial share of the costs of a gas pipeline, and so the way they are calculated could have major effects on a productivity trend.

- How will industry productivity trends be adjusted to take account of a regulated business's capacity utilisation and market prospects? Pipelines can have economies of scale, meaning that a pipeline with unused capacity and high demand growth could be able to increase its productivity more rapidly than a pipeline that is fully utilised or experiences little demand growth.
- How will industry productivity trends be adjusted to take account of a regulated business's ability to match the industry's rate of 'embodied technical change'? The productivity of old pipelines cannot grow as fast as that of newly installed pipelines, given that improvements in pipeline technology are occurring all the time and, once installed, a pipeline will operate for many years and hence over time become less and less able to match the productivity of a new pipeline.

The US experience in using productivity-based price caps, as summarised by PEG, reinforces the Commission's concerns. For example, PEG noted that most US productivity-based price caps have been approved for distributors that have relatively stable productivity trends:

> … an industry's historical TFP [total factor productivity] trend has been viewed as a reliable guide to future TFP growth … [because] these TFP trends have, in fact, been fairly stable. This partly reflects the nature of the industries. Most [price cap] plans have been approved for gas and power distributors, and output and investment growth in these industries is often, although not always, relatively stable over time. (sub. DR113, p. 17)

Hence, historical productivity trends have tended to be used in cases where they are likely to be a good predictor of future efficiency gains. This is unlikely to be the case for all regulated businesses. PEG noted that productivity growth tends to be more volatile for transmission businesses than it is for distributors, and so it could be inappropriate to use historical productivity trends to set price caps for transmission:

> Investments in these [electricity and gas transmission] industries provide for bulk energy transfers from supply sources to large energy users and distribution points. Such large investments tend to be 'lumpier' compared with energy distribution infrastructure, which is more often added in smaller increments in response to customer and demand growth. All else equal, a period when large, lumpy investments are made will be one where input quantity growth expands rapidly and TFP [total factor productivity] growth (equal to the difference between output and input quantity growth) accordingly declines. By the same token, a period where investments are either not necessary or are not undertaken is more likely to register relatively rapid TFP growth. The lumpiness of investment is therefore likely to make TFP trends in the power and gas transmission industries less stable than for either power or gas distribution. This could limit the appeal of such an approach in these industries, but this issue deserves more detailed examination. (sub. DR113, pp. 17–18)

The above quote also highlights why it can be inappropriate to assume that businesses are sufficiently homogeneous that they can increase productivity at a similar rate to the industry as a whole.

PEG noted that US regulators tend to adjust historical productivity trends upwards by a 'stretch factor' or 'consumer dividend' when setting a price cap. The rationale is that future productivity growth should be higher than historically, because 'lower powered' forms of regulation were used in the past and these provided little incentive to raise productivity:

> … industry TFP [total factor productivity] trends are necessarily estimated using the industry's historical data. Many utility industries have historically been subject to lower-powered regulatory schemes, like rate of return regulation. Economists generally believe that rate of return regulation does not create optimal incentives to contain unit cost. Industry TFP and input price trends calculated from historical data will naturally reflect the industry's historical unit cost performance under these low-powered regulatory mechanisms. (sub. DR113, p. 5)

PEG claimed that adjusting historical productivity trends has helped to ensure general acceptance of productivity-based price caps. It also noted that stretch factors have usually been set by (subjective) judgment rather than on the basis of quantitative techniques:

> … TFP [total factor productivity] is a well-accepted [productivity based] technique [for US regulation] and has tended to produce stable results in repeated applications. There has also been little controversy in these [price cap] plans about whether past TFP growth is a good proxy for expected TFP growth. In part, this is because X factors in these plans include a (firm-specific) stretch factor that reflects the company's expected TFP acceleration relative to the industry's historical norms. The value of this consumer dividend has typically been set by judgment … (sub. DR113, p. 17)

However, PEG argued that there are quantitative techniques that can be used to ensure that an appropriate productivity trend is used to set a regulated business's price cap:

> Various techniques can be used to isolate the expected long-run TFP [total factor productivity] trend, especially econometric techniques that can 'decompose' TFP growth into various components. PEG personnel presented econometric decompositions of TFP growth trends in our work for San Diego Gas and Electric. This issue may also be relevant when implementing productivity-based regulation in Australia and deserves greater attention. (sub. DR113, p. 18)

It is important to ensure that productivity-based price caps do not incorporate significant measurement errors or fail to take account of major differences between businesses that make it impossible for them to achieve the industry rate of productivity growth. Gas pipelines vary enormously and so using an industry measure of productivity growth to set an individual business's price cap could be inappropriate unless it can be accurately adjusted to reflect the characteristics of that business. It is debatable whether such empirical accuracy is achievable, even with the use of econometric techniques.

Recent developments

The Commission recommended in the national access regime inquiry that developmental work be undertaken on the measures needed to implement a productivity-based pricing regime (PC 2001c). The Utility Regulators Forum responded to this recommendation by commissioning a study of index-based approaches by Farrier Swier Consulting (2002). This study considered the options listed in table 7.2 and concluded that, in principle, total factor productivity (TFP) based approaches are likely to be superior. However, the study also concluded that the effectiveness of possible options depends on detailed design features.

Table 7.2 **Possible options for setting price caps[a]**

Approach	*Price cap at start of access arrangement period (P_0)*	*Growth rate of price cap during the access arrangement period (X)*	*Price cap at start of next access arrangement period (P_{0+t})*
Building block			
Pure building block approach	Building block	Building block	Building block
Index methods			
TFP with building block resets	Building block	TFP	Building block
TFP ongoing with option to trigger building block reset	Building block	TFP	TFP from P_{0+t}
Indexation against a comparable basket of services	Building block	Indexation against a comparable basket of services	Building block or TFP from P_{0+t}
Frontier methods			
DEA	DEA	DEA (indirect)	DEA
DEA from building block	Building block	DEA (indirect)	Building block or DEA
Engineering economic model (EEM)			
Pure EEM	Building block	EEM	Building block or EEM

[a] TFP refers to approaches that are based on estimates of total factor productivity. DEA refers to approaches that are based on estimates using data envelopment analysis.

Source: Farrier Swier Consulting 2002.

Following the somewhat inconclusive findings by Farrier Swier Consulting (2002), the Utility Regulators Forum facilitated further discussion about index and productivity-based pricing.

In September 2002, the URF [Utility Regulators Forum] released a discussion paper inviting comment on the Farrier Swier report with the intent of engaging interested parties in a discussion about pricing options for regulated networks. In May 2003, the URF invited interested parties to participate in, and attend, a one day seminar on the issue of total factor productivity-based pricing. (ACCC, sub. 48, p. 47)

However, little progress seems to have been made in identifying an approach that can be implemented by regulators.

The debate on access pricing that has emerged does not indicate a clear view on which is the preferred approach. (ACCC, sub. 48, p. 47)

Nevertheless, the ESC argued that the Gas Code should be amended so that TFP based approaches can be adopted:

… longer-term work is required to develop the TFP method to a stage at which it is understood, accepted and able to be implemented effectively. Nevertheless, the … [Essential Services Commission] … considers that it would be appropriate to amend chapter 8 of the Gas Code to permit regulators to adopt alternative approaches to determining price caps, including the TFP approach … (sub. 51, p. 12)

As noted above, the Commission has recommended that s.8.5 of the Gas Code be amended to provide scope to use an alternative method to the building block approach. This would open the possibility of using productivity-based regulation, provided the regulator was satisfied that the service provider’s proposed approach is more likely to meet the overall objective of the Gas Access Regime.

The ESC acknowledged that many issues will need to be addressed before a TFP-based approach can be adopted:

… it is important to recognise some of the challenges of moving to a TFP approach in the regulatory context, including:

- ensuring robust, consistent historical cost data are available over a suitable period on which to base industry productivity indices
- applying TFP indices across industries and companies on an appropriate basis that accounts for different operating environments faced by individual businesses (for example, urban versus rural customer bases, and cost differences due to variations in geographic, network and other characteristics)
- accounting for step changes in costs as a result of government policies or new environmental and safety standards
- establishing the implementation arrangements (for example, whether there is a need for a transitional period during which returns are subject to floors or caps)
- incorporating appropriate incentives … to ensure regulated businesses do not trade off efficiency gains with lower levels of reliability

- educating regulated businesses and stakeholders so they understand and accept such an approach. (sub. 51, pp. 11–12)

The research and discussion that has followed the Productivity Commission's review of the national access regime suggests that further work on index and productivity-based pricing methods is unlikely to be fruitful. In any case, such pricing methods would not remove many of the problems with the current building block approach, such as the potential for regulatory error and the distortion of investment. The US experience outlined by PEG reinforces the Commission's concerns. In essence, problems arise with price regulation because regulators have a direct role in pricing, regardless of whether prices are set on the basis of productivity-based techniques or detailed cost reviews.

FINDING 7.4

The Commission supports continuing efforts to find improved ways of determining the path of reference tariffs from one access arrangement review to the next.

7.4 Capital base

As noted in chapter 2, the vast majority of pipeline costs are attributable to fixed capital expenditure. Hence, the determination of reference tariffs is highly dependent on how capital assets are valued and the method used to calculate depreciation.

Determining the initial capital base

In order to calculate a revenue target, it is necessary to have a value for assets at the start of an access arrangement period (box 7.7). This is termed the initial capital base. How the initial capital base is valued depends on whether there was a prior access arrangement and which method is used to calculate target revenue (box 7.8).

There have been significant transitional problems in valuing pipelines built prior to the adoption of the Gas Access Regime. This can be attributed at least in part to the many factors that regulators have to consider in valuing such pipelines. In particular, s.8.10 of the Gas Code lists ten factors to consider and adds that any other factors may be considered if the regulator sees them as being relevant. Further, the August 2002 judgment by the Supreme Court of Western Australia regarding the Dampier–Bunbury pipeline (*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231) indicates that the multiple factors listed in s.2.24 of the Gas Code must also be considered in valuing assets that existed prior to the commencement of the Gas Code.

Box 7.8 **Determining the initial capital base in an access arrangement**

For **pipelines that existed at the commencement of the Gas Code**, various factors (specified in s.8.10 of the Gas Code) should be taken into account in determining the initial capital base for the first access arrangement. This includes the value of the pipeline using the depreciated actual cost (DAC) and depreciated optimised replacement cost (DORC) methods; the asset value from applying other well recognised methods; the advantages and disadvantages of each method; international best practice; how tariffs were set in the past; reasonable expectations under previous regulatory arrangements; and any other factors that a regulator considers relevant. As additional guidance, s.8.11 of the Gas Code states that the initial capital base 'normally should not' fall outside the range of values derived from the DAC and DORC methods.

For **new pipelines**, the initial capital base is the actual capital cost at the time of entering service. However, if the period between when a pipeline first enters service and when a reference tariff is proposed is such as 'reasonably to warrant adjustment', then the capital base may be adjusted to account for new facilities investment, depreciation and redundant capital.

When an access arrangement has expired, the capital base applying at the expiry of the previous access arrangement is adjusted as if that access arrangement had remained in force. The adjustments account for new facilities investment, depreciation, and redundant capital. According to s.8.9 of the Gas Code, the initial capital base using the cost of service method should be calculated as:

$$K_{t-1} + I^*_{t-1} - D_{t-1} - RK_t$$

where $K_{t\text{-}1}$ is the capital base at the start of the previous access arrangement; I^*_{t-1} is the portion of new facilities investment in the previous access arrangement period that qualifies for incorporation into the capital base; $D_{t\text{-}1}$ is regulatory depreciation during the previous access arrangement period; and RK_t is redundant capital identified prior to the start of the new access arrangement (assets removed from the capital base because they no longer contribute to the delivery of services, provided that a mechanism for such removal exists in a service provider's reference tariff policy). Using the IRR or NPV methods, the initial capital base is calculated as:

$$RV_{t-1} + I^*_{t-1} - RK_t$$

where $RV_{t\text{-}1}$ is the residual value assumed in the previous access arrangement period. $RV_{t\text{-}1}$ should reflect notional depreciation that meets the principles used to calculate $D_{t\text{-}1}$ for the cost of service method.

In comparison, the valuation of pipelines built since the Gas Code commenced is relatively straightforward. In essence, assets are valued at cost and then their value is reduced over time to account for regulatory depreciation and, in some cases, ‘redundant capital’ (details discussed below).

BHP Billiton viewed the Gas Code’s approach on asset valuation as beneficial to both service providers and pipeline users:

> … the most important feature of the [Gas] 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 reopened 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. (sub. 26, p. 90)

New facilities investment

Over the life of an access arrangement, it is possible that a service provider will incur some capital costs in extending or expanding its pipeline. For this reason, the Gas Code (ss8.15–8.26) includes provisions on how the costs of new facilities investment can be recovered from users.

At the commencement of a new access arrangement, the capital base can be increased to reflect the costs of new facilities investment that occurred in the previous access arrangement period. The additional capital costs must be prudent, in the sense that the service provider acts efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services (s.8.16). If the anticipated increase in revenue from a new facility is below its cost, then the regulator has to be satisfied that the new facility either:

- generates systemwide benefits that justify the approval of a higher reference tariff for *all* users
- is necessary to maintain the safety, integrity or contracted capacity of services.

For the purposes of determining if an investment is prudent, regulators must consider:

- whether a new facility exhibits economies of scope or scale
- the increments in which capacity can be added

- whether the lowest sustainable cost of delivering services over a period of time might require a new facility with capacity to meet forecast sales over that time frame.

The above approach seems to strike a reasonable balance between the constraints facing service providers and the interests of users in not guaranteeing a return on imprudent investments. However, implementation might be constrained by the information asymmetry between regulators and service providers. In this regard, the ACG noted:

> 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. (BHP Billiton, sub. 26, attachment, p. 24)

A regulator's concern about information asymmetry might lead it to err in a way that disadvantages service providers. A possible example is the approach taken by the ACCC for the capital base of the Moomba–Adelaide pipeline. Rather than accept the valuation submitted by the service provider (Epic Energy), the ACCC decided to undertake a detailed examination and hired consultants to help it do so. The ACCC ended up drafting the access arrangement, which was based on the lowest cost of line pipe quoted by one of its consultants. In reviewing this decision, the Australian Competition Tribunal found that the ACCC had made an error:

> In taking the approach it did, the ACCC exposed Epic to an asymmetric risk whereby the likelihood of underestimating the true actual line pipe cost was much greater than that of overestimating it. To take the lowest price from one source of supply, runs the risk of serious commercial understatement of the expected cost of line pipe. (para. 94)
>
> … As a consequence, the Final Approval has been affected by reviewable error and it becomes necessary for the Tribunal to make orders to remedy the ACCC's error. (para. 96) (*Application by Epic Energy South Australia Pty Ltd* (2003) ACompT 5)

Forecast capital expenditure

Reference tariffs may be determined on the basis of investment that is forecast to occur in the forthcoming access arrangement period. This is conditional on the forecast investment being 'reasonably expected', when it occurs, to meet the criteria (s.8.16) for inclusion in the capital base (prudent and so forth).

A service provider can specify in its reference tariff policy how its initial capital base will be adjusted if actual investment turns out to be different from forecast investment. Otherwise, the adjustment (if any) will be decided by the regulator when considering the next access arrangement. The ACCC (2002a, p. 44) expressed a preference for a ‘symmetric adjustment mechanism’, which adjusts regulatory parameters both when actual capital expenditure is below and above forecast.

Section 8.21 of the Gas Code allows a regulator to agree in advance (possibly with conditions or limitations) that a forecast investment will meet the requirements for inclusion in the capital base. This has the effect of binding the regulator’s decision when it considers revisions to an access arrangement. However, the AGA (sub. 13, p. 70) noted that this provision has only been used once, possibly because regulators require a public consultation process like that for a full access arrangement review. Similarly, Epic Energy claimed:

> … service providers are provided with no certainty that the costs associated with the new facilities investment will be included in the capital base at the time the capital expenditure needs to be incurred. (sub. 37, p. 40)

Nevertheless, the ESC (2004a) recently made a draft decision on proposed new facilities investment — the Bairnsdale Gas Extension — that provided Envestra with some certainty. In particular, the ESC agreed that the investment would meet the requirements of the Gas Code, provided that actual expenditure did not vary from the forecast by more than 10 per cent:

> The [Essential Services] Commission agrees that the $7.05 million … plus a 10 percent margin, that Envestra proposes to spend on providing reticulated gas to Bairnsdale is New Facilities Investment. Further, in accordance with section 8.21 of the [Gas] Code, the Commission agrees that this forecast New Facilities Investment will meet the requirements of section 8.16(a) of the Code.
>
> The Commission does not agree that any expenditure incurred by Envestra in reticulating natural gas to Bairnsdale that exceeds the forecast expenditure of $7.05 million … plus a 10 percent margin, is New Facilities Investment that will meet the requirements of section 8.16(a) of the Code. The Commission may consider whether those requirements are met in respect of the excess expenditure at the next Access Arrangement Review. (ESC 2004a, p. 3)

The Productivity Commission endorses — as is envisaged in the Gas Code — regulators being able to provide some certainty regarding the treatment of forecast investments. The limited use of s.8.21 of the Gas Code suggests that the associated process needs to be simplified. The Commission considers that a suitable way to do this is to give regulators greater discretion regarding the extent of public consultation.

RECOMMENDATION 7.6

Section 8.21 of the Gas Code should be amended so that regulators can, at their discretion, undertake less public consultation than is required for a proposed revision to an access arrangement under s.2.28. If this discretion is exercised, the regulator should issue a written statement outlining clearly why the reduced public consultation was justified prior to issuing a binding decision under s.8.21 that proposed investment in an extension or expansion of a covered pipeline would meet the requirements for incorporation into the capital base.

Speculative investment

If a portion of new facilities investment does not qualify for incorporation into the capital base, then it may be added to a 'speculative investment fund' (ss8.18–8.19). Should subsequent changes in demand cause any part of a speculative investment to qualify as part of the capital base, then an amount from the speculative investment fund may be incorporated into the capital base. An example of speculative investment might be where a service provider adds a compressor that increases capacity beyond the forecast demand approved by the regulator. The Gas Code's approach to speculative investment seems to provide a balance between facilitating entrepreneurial activity and not guaranteeing every entrepreneurial investment a return, assuming that pipeline owners are free to negotiate prices for speculative investments.

Capital contributions volunteered by users

A new facility investment can be added to the capital base when a user agrees to pay more than the relevant reference tariff in order to fund the new facility. The excess amount paid by the user is termed a 'capital contribution' (s.8.23).

Orica expressed concerns that capital contributions prior to the commencement of the Gas Code were not adequately recognised by regulators:

> Although the NSW regulator has discounted historical capital contributions made by large Users toward the Wilton to Newcastle pipeline, Orica is firm in its belief that the existing distribution tariff levels do not accurately reflect this contribution and have not provided a return to its business over and above that available to all users. It is recognised that the [Gas] Code does make allowances for capital contributions by users toward new facilities since the commencement of the Code, however, retrospective provisions need to be incorporated to provide a return (by way of tariff reduction, discounts, tariff 'holidays' or other concessions) to specific users to reflect the risk undertaken in making historical capital contributions to incumbent distribution pipeline

> owners, who, via the Code, have been provided with guaranteed excessive returns from those same contributors. (sub. 28, p. 7)

Western Power was concerned that the Gas Code has not facilitated expansions that users are willing to fund:

> It is critical that a user that is seeking an expansion of a pipeline and is willing to fund the expansion is able to obtain an expansion. It is clear from section 6 of the Gas Code that this is an aim of the Gas Access Regime, but so far the Gas Access Regime has failed to deliver on this aim. (sub. DR115, p. 3)

It also noted:

> … arbitrated expansion is arguably the most critical aspect of the Gas Code. Historically in Western Australia arbitrated expansion has been difficult to secure. Users' rights in respect of arbitrated expansion under the Gas Access Regime must be at least maintained and preferably must be strengthened. (sub. DR115, p. 43)

Western Power's concerns reflected its lack of success in getting Epic Energy to build a user funded expansion of the Dampier–Bunbury pipeline:

> Epic Energy has exercised its market power and increased its negotiating leverage by refusing to expand the capacity of the DBNGP [Dampier–Bunbury pipeline]. … WPC [Western Power Corporation] emphasises that it has been seeking an expansion of the DBNGP for a number of years. WPC is willing to fund the expansion in order to secure additional capacity, but despite WPC's willingness to make a financial contribution to the expansion, Epic Energy has steadfastly refused to expand the DBNGP. (sub. DR115, pp. 2–3)

The Commission notes that s.6 of the Gas Code gives an arbitrator the power to require a service provider to build a user funded expansion. It appears that the problems experienced by Western Power to date have been driven by relatively unusual factors that cannot necessarily be addressed by amending the Gas Code. In particular, Epic Energy had experienced significant financial difficulties for several years and it was, over an extended period, in dispute with the regulator regarding the access arrangement for the Dampier–Bunbury pipeline, meaning that the arbitration provisions of the Gas Code could not be invoked.

Surcharges on users of incremental capacity expansions

As an alternative to a capital contribution, users have the option — subject to agreement by the service provider — of paying a surcharge in order to fund all or part of the cost of an incremental capacity expansion (ss8.25–8.26). If a regulator approves a surcharge, then it is binding in an access dispute.

The Gas Code's definition of a surcharge notes that the relevant increase in capacity cannot be included in the capital base in subsequent access arrangement periods:

> A Surcharge is a Charge in addition to the Charge that would apply under a Reference Tariff for a Reference Service (or, in relation to another Service, under the Tariff that would be determined by the Arbitrator in arbitrating an access dispute under section 6) that is levied on Users of Incremental Capacity in order for the Service Provider to recover some or all of the cost of New Facilities Investment that can not be recovered at the Prevailing Tariffs (and so cannot be included in the Capital Base in subsequent Access Arrangement Periods). (Gas Code, s.8.25)

The approval of a surcharge also means that the relevant investment cannot be included in the speculative investment fund, ensuring that the investment's cost cannot be recovered via a reference tariff at a later date.

Epic Energy noted:

> Pipeline capacity expansion does not automatically imply an increase in tariffs. The marginal costs of some expansions are lower than the average cost of capacity. Those expansions result in a lowering of tariffs determined on an average cost basis. However, not all expansions have this desirable outcome. When a pipeline is fully compressed, additional capacity must be obtained by looping (duplicating sections of the line). Initial looping typically has marginal costs which exceed the average cost of capacity and, when undertaken, increases tariffs that have been determined on an average cost basis. (sub. 37, p. 57)

Epic Energy (sub. 37, p. 58) also noted that for the Dampier–Bunbury pipeline it had proposed a tariff path that reflected the expectation that the pipeline's capacity would be more than doubled over the next 10 years. Its proposed access arrangement was designed to ensure that expansions did not result in increased reference tariffs for all customers; and the same tariff would be payable regardless of whether a customer was using the original or incremental capacity. The tariff path was smoothed over an extended period to reflect an expectation that the expansions would be made without increases in the tariff at the time the expansions occurred. The proposal was rejected by the regulator (OffGAR).

According to s.8.26 of the Gas Code, surcharges may be levied provided that:

- they are designed to recover the costs of prudent investment
- they do not include costs that are in the speculative investment fund
- the structure of surcharges reflect a 'fair and reasonable' sharing of the total recoverable cost between incremental users.

The final criterion listed above is not consistent with the Commission's recommended pricing principles. In particular, s.8.26(c) of the Gas Code has a potentially conflicting requirement that the structure of surcharges provide for a 'fair and reasonable' sharing of costs. This requirement should be removed.

RECOMMENDATION 7.7

To ensure there is no conflict with the pricing principles specified in recommendation 7.1, s.8.26(c) of the Gas Code should be deleted.

Investment with only diffuse beneficiaries

The Victorian Department of Infrastructure raised a concern about:

> … [pipeline] augmentations for which the beneficiaries are likely to be diffuse. In particular, while new large customers — like a gas fired generator — would be expected to be in a position to contract to underwrite augmentations required to serve their load, it is less likely that there will be a party who will be in a prepared to underwrite the network augmentations required for general load growth. In particular, if there is no readily identifiable beneficiary, even though a pipeline expansion would appear to provide benefits to a range of users, it is unlikely that a single party will volunteer to underpin an investment that will also benefit others (that is, there is a 'free rider' effect). (sub. DR104, p. 21)

The Department went on to observe that:

> The intended treatment of these projects under the regime at present would appear to be for the service provider to propose an augmentation, and then to present a case to the regulator that the project generates 'systemwide benefits' [as required under s.8.16(a)(ii)(B) of the Gas Code] and so should be rolled in to the provider's regulatory asset base. (sub. DR104, pp. 21–2)

However, the Victorian Department of Infrastructure expressed doubts about the effectiveness of the systemwide benefits test in the Gas Code:

> … the systemwide benefits test itself would appear to be flawed, and create an impediment to these projects. In particular, the requirement for the regulator to be convinced that the 'systemwide benefits' justify a price rise 'to all users' has been interpreted as requiring that the benefits also accrue to all users — which is an impossible hurdle for any project to meet. A more relevant test would be to ensure that the particular project delivered net benefits across the whole market (and greater net benefits than alternative means of meeting the same need). (sub. DR104, p. 22)

The Commission agrees that the Gas Code's systemwide benefits test is not well suited to dealing with augmentations that have diffuse beneficiaries. However, the Commission considers that the best approach is for regulators to use other parts of the Gas Code in a way that explicitly acknowledges the greater risk associated with such projects. This could, for example, include allowing a greater *ex ante* regulatory rate of return when setting reference tariffs.

Redundant capital/asset stranding

Regulators can impose the requirement that reference tariff policies include a mechanism for removing ‘redundant capital’ — assets that no longer contribute to the delivery of services — from the initial capital base of the next access arrangement. The Gas Code (s.8.27(b)) notes that this is done so as to share the costs associated with a fall in demand between the service provider and users.

Before approving a mechanism to remove redundant capital, the regulator must take account of how the resulting uncertainty would affect service providers and users (s.8.27). If such a mechanism is approved, then the determination of the *ex ante* regulatory rate of return and the economic life of assets should take account of the resulting risk to the service provider. Redundant capital can be reincorporated into the capital base if at a later date it contributes to the delivery of services.

A reference tariff policy may include (and the relevant regulator may require it to include) other mechanisms that have the same effect on reference tariffs as a redundant capital mechanism, but which do not reduce the capital base (s.8.29).

Service providers expressed concerns about how the redundant capital section of the Gas Code can lead to the ‘stranding’ of assets:

> Service providers are exposed to the risk that parts of their pipeline systems may be treated as being redundant because regulators believe that the capacity they provide is not required during the next regulatory period, and can use the discretion they have under the national Gas Code to impose this belief. Regulators give no consideration to the fact that businesses operating in (real, not theoretical) competitive markets have spare capacity from time to time. (Epic Energy, sub. 37, pp. 34–5)

> Access regulation presently allows regulators to ‘strand’ assets, in whole or in part, if they are not fully utilised. Thus, if the investor sizes an asset to take advantage of economies of scale, there is the attendant risk that the assets will at some time be stranded. This sends strong messages to investors to ‘size’ assets so that at all times there is no excess capacity. The result is that valuable economies of scale are not realised. (AGL, sub. 32, p. 36)

> A key risk facing regulated gas businesses making investment decisions … is that a regulatory authority may apply asset or cost ‘optimisation’ on the basis of knowledge not available to the regulated gas business or the regulatory authority at the time of investment. This has the potential to result in regulated businesses not recovering the initial costs of investments which were financially and technically prudent at the time of the decision to invest. … Asset stranding can have significant consequences for investment in new infrastructure assets and the ability of regulated businesses to commit capital to reinvestment in existing assets. While asset stranding is commonly justified by reference to competitive markets the potential for stranding under any regulatory regime will be reflected in higher costs of capital for the regulated business which will ultimately be reflected in increased access charges. (AGA, sub. 13, p. 68)

The Commission agrees that redundant capital mechanisms increase the risk faced by service providers. However, businesses face demand risk in most industries. If regulators do not have the scope to remove redundant capital, then it seems likely that demand risk will be transferred to users (to the extent that users are unable to substitute other fuels). Nevertheless, regulators should apply redundant capital mechanisms with caution, since they could have unintended consequences. It should also be noted that redundant capital can be reincorporated into a service provider's capital base if at a later date it contributes to the delivery of services.

Regulatory depreciation

If target revenue is calculated using the cost of service method, then it is necessary to determine the amount and timing of regulatory depreciation. This might differ from depreciation calculated for company reporting and tax purposes.

Section 8.33 of the Gas Code states that, when using the cost of service method, the regulatory depreciation schedule should be designed so that:

- reference tariffs change over time in a manner that is consistent with efficient market growth of services. This might involve a large share of regulatory depreciation taking place in the future, particularly where the calculation of reference tariffs has assumed significant market growth and the pipeline has been sized accordingly (s.8.33(a))
- assets are depreciated over their economic life
- to the maximum extent that is reasonable, the regulatory depreciation schedule is adjusted over time to reflect changes in the expected economic life of assets.

When the IRR or NPV method is being used, there is a notional regulatory depreciation schedule which comes from the residual value calculations. The residual value of capital should be consistent with the requirements for cost of service regulatory depreciation. Reference tariffs should also change over time in a manner that is consistent with efficient market growth of services (s.8.34(d)).

In implementing the depreciation requirements of the Gas Code, regard must be had to the reasonable cash flow needs for noncapital costs, financing cost requirements and similar needs of a service provider (s.8.35).

The ACCC stated that the 'straight line' method is most commonly used to calculate regulatory depreciation:

> Standard straight line depreciation over the economic life of the asset has typically been the methodology used when depreciating a pipeline's capital base. (sub. 48, p. 54)

Regulatory depreciation and tariff paths

The ACCC claimed that, provided an investor recoups its investment, the timing of regulatory depreciation is immaterial:

> Depreciation is a notional cost in any particular year of the pipeline's operation. As long as the service provider is able to recover the total investment in the asset over the life of the pipeline, the depreciation amount in any particular year may be of little importance across a wide range of possibilities. (sub. 48, p. 36)

However, in its post-tax revenue handbook, the ACCC also recognised that the timing of regulatory depreciation will determine how reference tariffs change over time. This will in turn affect the ability of investors to recover their investments:

> The pattern of depreciation applied determines the time profile of tariffs and for this reason some constraints on the depreciation path are desirable. (ACCC 2001a, p. 11)

Hence, ss8.33(a) and 8.34(d) of the Gas Code require regulatory depreciation to be set so that reference tariffs change over time in a manner that is consistent with efficient market growth. Regulators must also be mindful of s.8.1(d) of the Gas Code, which states:

> A Reference Tariff … should be designed with a view to achieving … efficiency in the level and structure of the Reference Tariff …

The ACCC (2001a) noted that its draft regulatory principles suggest that regulated tariffs should mimic the properties of prices in competitive markets. It summarised the implications for regulatory depreciation as follows:

> Such an objective may favour depreciation profiles that produce a level time profile for tariffs. However, there may be some circumstances (e.g. threat of bypass) where other depreciation profiles (such as accelerated depreciation) may be more appropriate. (ACCC 2001a, p. 11)

In its post-tax revenue handbook, the ACCC (2001a) detailed how the timing of regulatory depreciation can be manipulated to ensure a desired tariff path. The ACCC noted that there is considerable flexibility in this regard:

> … there is considerable flexibility available in the time profile of depreciation to smooth the revenues over time or to achieve desired price paths. (sub. 48, p. 35)
>
> … the time path for depreciation can be viewed as arbitrary. As long as the rate of return on the residual RAB [regulatory asset base] value at any point in time is expected to be achieved, the NPV of expected cash flows will equate to the RAB. (ACCC 2001a, p. 10)

To illustrate the flexibility of the Gas Code with respect to regulatory depreciation, the ACCC referred to the access arrangement for the Central West Pipeline (Marsden–Dubbo):

> The Central West Pipeline (CWP) access arrangement final decision provided for the use of economic depreciation as part of the service provider's NPV/price path methodology to determine total revenue. Thus the CWP could set lower tariffs in the initial stages of the life of the pipeline enabling greater opportunities for market development and also have the opportunity to later recoup under recoveries accrued in the early period of the life of the pipeline. (sub. 48, p. 54)

However, Enertrade was critical of this approach:

> The Central West Pipeline solution … [that the ACCC] … came up with was negative depreciation on that extra capacity — 'We'll just defer the cost out and future customers can pay it'. (trans., p. 282)

The Commission's assessment

The Commission notes that regulatory depreciation can be adjusted in order to meet certain objectives. While some of these objectives — such as ensuring smooth tariff paths or allowing market development for new pipelines — might be appropriate, the adjustment of regulatory depreciation adds complexity to the regime. For example, the ACCC (2001a) stated in its post-tax revenue handbook that:

> It may be the case that the revenue resulting from the building block approach is not smooth over the access arrangement period (for example, as a result of capital expenditure). Where this is the case the [Australian Competition and Consumer] Commission prefers to smooth the time profile of revenues by constraining it to follow a CPI-X path to prevent volatility in the reference tariff. Under this approach, revenues are increased annually by CPI-X where X is set such that the NPV of the smoothed revenue stream is equivalent to the NPV of the unsmoothed revenue stream. … It should be noted that the X factor relates purely to a price adjustment mechanism. It has little or nothing to do with actual productivity improvements …
>
> Even where the building block revenue is smooth … and forecast volumes are not, then resulting reference tariffs will tend to be discontinuous over the access arrangement period. In this situation the Commission would also apply a similar approach to that discussed above but would focus on the level of tariffs rather than revenues. That is, a CPI-X formula would be applied annually to the reference tariff. In this case, when the X is specified the level of the tariffs is adjusted. Otherwise, tariffs in the first year (or last year if continuity with the next regulatory period is vital) are left unchanged and the X adjusted to achieve the desired NPV equivalence in expected revenues. (ACCC 2001a, p. 24)

This complexity is compounded by an apparent tendency by regulators to use regulatory depreciation to deal with the deficiencies of the Gas Code's target revenue approach. For example, the ACCC (2001a, pp. 20–2) outlined a 'normalisation procedure' that adjusts depreciation in order to ensure that rapid changes in a service provider's tax liabilities do not lead to volatility in target revenue. Another example is the capitalisation of losses in order to limit a service provider's downside risk (adding losses to the capital base so that they can be recovered at a later date through regulatory depreciation):

> …. capitalisation of financial losses is the preferred mechanism. This enables a more satisfactory return to be achieved even in a black sky [downside] scenario but over a longer timeframe. (ACCC 2002a, p. 36)

The capitalisation of losses is considered further in chapter 9.

While it is appropriate to include provisions relating to depreciation in the Gas Code, the existing provisions need to be revised so they are consistent with the Commission's recommended objects clause and pricing principles. In particular, s.8.32 should refer to the pricing principles to be included in s.8.1; and ss8.33(a) and 8.34(d) should be amended so that depreciation does not necessarily have to involve an allocation of costs between individual reference services.

RECOMMENDATION 7.8

To ensure there is no conflict between the depreciation provisions of the Gas Code and the pricing principles specified in recommendation 7.1, ss8.32, 8.33(a) and 8.34(d) should be replaced with the following:

s.8.32 ***The Depreciation Schedule is the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of satisfying the pricing principles in section 8.1.***

s.8.33(a) ***so as to result in the expected Total Revenue attributable to a Service Provider's Reference Services in aggregate (not individual Reference Services when there is more than one) changing over time in a manner that is consistent with the efficient operation and use of the Services (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of Total Revenue has assumed significant market growth and the Pipeline has been sized accordingly);***

s.8.34(d) ***the expected Total Revenue attributable to a Service Provider's Reference Services in aggregate (not individual Reference Services when there is more than one) should change over the Access Arrangement Period in a manner that is consistent with the efficient operation and use of the Services (and which may involve a substantial portion of the depreciation taking place towards the end of the Access Arrangement Period, particularly where the calculation of Total***

Revenue has assumed significant market growth and the Pipeline has been sized accordingly).

7.5 *Ex ante* regulatory rate of return

In order to calculate target revenue, it is necessary to set an *ex ante* regulatory rate of return on capital (denoted as *r* in box 7.7). This expected rate of return has to be commensurate with prevailing conditions in the market for funds and the risk involved in delivering relevant reference services (s.8.30).

The *ex ante* regulatory rate of return can be determined using any method, provided the regulator is satisfied that it is consistent with the reference tariff objectives contained in s.8.1 of the Gas Code (s.8.31). In practice, it appears that the *ex ante* regulatory rate of return is usually based on an estimate of the weighted average cost of capital (WACC). This weights the rates of return required by a business's equity investors and debt providers by, respectively, the amount of equity and debt relative to the business's total capital.

While the debt costs of a service provider are relatively straightforward to assess, the return required by equity investors is not. The return on equity is typically estimated using the capital asset pricing model (CAPM). This method depends on the measurement of two contentious variables — a service provider's 'beta' (a measure of its risk relative to that of the total market for risky investments) and the market risk premium (box 7.9).

Implementing the WACC/CAPM approach is not a precise science, given the numerous debatable assumptions involved. There is even disagreement on the precise formulas to use, due to different views on how issues such as tax should be treated. Hence, a range of plausible values can be generated for the regulatory rate of return using the WACC/CAPM approach. This in turn implies that meeting the Gas Code's requirements does not automatically lead to a single indisputable number for a reference tariff.

The ACCC (sub. 48, p. 39) agreed that cases can arise where a range of plausible values exists for a regulatory parameter. It went on to note that in such cases it tends to rule in favour of service providers:

> … where there is doubt as to the most appropriate value of such variables, the ACCC has tended to make conservative assessments benefiting service providers to ensure that service providers have access to sufficient resources to continue to operate facilities and undertake new investment. This view is supported by the relative performance of regulated companies against equity markets and the findings of Moody's Investors Service on the regulatory regime in Australia compared to the UK. (sub. 48, p. 40)

Box 7.9 **Using the CAPM to determine the required return on equity**

The capital asset pricing model (CAPM) assumes that investors are rational in the sense that they eliminate all asset-specific risks by holding a diversified portfolio. As a result, the theory asserts that investors only need to be compensated for risks that affect the whole market of risky investments. Examples of such nondiversifiable risks are those arising from macroeconomic policy, recessions, and political unrest.

The CAPM attributes differences in returns between investments to the divergent responses that investments have to risks that affect the whole market. Accordingly, the CAPM specifies that an investment's expected return depends on how its returns vary relative to the total market of risky investments:

$$E[R_p] = R_f + \beta_p\left(E[R_m] - R_f\right)$$

where $E[R_p]$ is the expected rate of return on equity for a pipeline service provider; R_f is the rate of return on the risk-free asset (typically interpreted as a government bond); β_p is a pipeline service provider's equity 'beta' (a measure of how its returns vary in response to nondiversifiable risk, relative to how the market for all risky assets responds to such risk); and $(E[R_m] - R_f)$ is the expected risk premium for the market of all risky investments.

Finding values for the variables in the above equation so as to determine the required return on equity ($E[R_p]$) is not straightforward. R_f is usually based on the return on government bonds. But it is unclear what maturity should be used, and whether it should be the return on a particular day or an historical average. If it is an historical average, it is unclear what time period should be used.

There is no single widely agreed estimate for the market risk premium $(E[R_m] - R_f)$. Indeed, this premium might be changing over time and hence be difficult to estimate econometrically. For example, changes in the tax treatment of capital gains have probably altered the required premium on risky assets. The ACCC (sub. 48, p. 42) stated that 6 per cent is usually the value adopted for the market risk premium.

It is not possible to estimate β_p — which probably differs between distribution and transmission pipelines — using Australian data because there is an insufficient sample of traded shares in gas pipeline service providers. As a result, the beta for a particular service provider has to be approximated using beta estimates from other sectors and/or foreign pipeline companies. Such estimates have to be adjusted to reflect differences in the debt-equity ratio between businesses, because the equity beta tends to increase with gearing. This can be done by first using a 'delevering' formula to convert a business's estimated beta to an asset beta (the beta of a business with no debt). The result is then converted into a beta for the regulated service provider using a 'relevering' formula that is based on what is considered to be its appropriate debt-equity ratio. There are various problems with this process, including how the formulas take account of different tax systems between industries/countries; what is the appropriate gearing for a service provider; and whether a beta from another country might be affected by that country's different pipeline regulations.

As an example of its approach, the ACCC (sub. 48, p. 42) noted that it has adopted an equity beta of approximately 1.0 in its most recent decisions on access arrangements, despite empirical evidence suggesting that the true value is only 0.7 for Australian gas transmission businesses.

However, others did not see the current regulatory approach as benefiting service providers:

> Regulatory error, overreach and failure are evident in many aspects of the operation of the current gas access regime, including … adoption by regulatory authorities of unrealistic levels of theoretical precision in the application of cost-based access pricing methodologies such as the capital asset pricing model. (AGA, sub. 13, p. 22)

> … 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 has been 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 the 'normal' return on investment. (Ergas 2003b, p. 55)

> While the ACCC makes precise WACC determinations to two decimal places, the true cost of capital lies anywhere between a wide range and ACCC determinations have a low probability of being correct. (Allgas Energy, sub. 69, p. 4)

In addition, as noted previously, the Australian Competition Tribunal has found cases where the ACCC has erred in a way that has disadvantaged service providers (*Application by Epic Energy South Australia Pty Ltd* (2003) ACompT 5; and *Application by GasNet Australia (Operations) Pty Ltd* (2003) ACompT 6).

The AGA claimed that the WACC/CAPM approach is based on a theoretical model which assumes no efficiency improvements over time:

> The dominant cost based approach does not support investments in dynamic efficiency. The assumption of the capital asset pricing model is of a theoretically perfect market equilibrium featuring no management induced innovation or technological change, and regulators are constrained in addressing this theoretical limitation by an absence of information about, and expertise in, what constitutes an 'efficient' level of investment in innovation and research and development (a highly uncertain and theoretical concept itself) activities. (sub. 13, p. 53)

Allgas Energy was also critical, noting that the CAPM approach had been rejected by leading financial theorists:

> … there has been a prolonged and complex international debate on the validity of CAPM and alternatives by financial theorists. That debate probably reached its end-point when two of the most prominent theorists, Fama and French (1997) ['Industry costs of equity', *Journal of Financial Economics*, vol. 43, pp. 153–93] observed that:

- the CAPM is a 'dead horse' (p. 175), with estimates which are 'distressingly imprecise' (p. 178) and 'beset with massive uncertainty' (p. 179); and
- no other financial model is superior to CAPM.

That is, two of the most eminent of financial capital theory experts have concluded that the CAPM is inherently flawed as a measure of the cost of capital and no other financial model is any better. Shortcomings include, for example:

- a range of anomalies such as the small firm, value and January effects, and over-reaction, indicate that the model has limited explanatory power. A number of variables with little or no basis in finance theory explain differences in returns more effectively than the CAPM. In an extensive study, Fama and French (1992) ['The cross section of expected stock returns', *Journal of Finance*, vol. 47, pp. 427–65] found no systematic relationship between risk and return as measured by beta;
- it fails to deal with the multi-period nature of investments; and
- the degree of measurement error in identifying model parameters result in wide confidence intervals around point estimates of the cost of equity.

Alternatives to CAPM have been extensively studied and have been found to be worse. For example, the three-factor model developed by Fama and French … has now been classed as inferior by its inventors … (sub. 69, p. 14)

Epic Energy noted that:

It is not the task of the Regulator to determine values for parameters of an access arrangement which it thinks are consistent with the [Gas] Code. Rather, its role is to assess whether the values proposed by the Service Provider are consistent with the Code and fall within a range of values that are reasonable. (sub. DR109, p. 1)

APIA observed that the role of regulators was clarified in recent decisions by the Australian Competition Tribunal:

An important insight from the Tribunal's decisions is that the regulator's role is to assess whether an Access Arrangement falls within a reasonable range before amending it. This is a fundamentally different approach from that which has been adopted by regulators to date, where the regulator has felt empowered to substitute its view for that of the service provider, irrespective of whether or not the service provider's position fell within a reasonable range. (sub. DR100, p. 11)

Given that the CAPM is a theoretical model based on debatable assumptions, the Commission is concerned that the model has become a de facto requirement under the regime. This situation might have been facilitated by s.8.31 of the Gas Code, which describes the CAPM as a 'well accepted financial model'. The comments of the leading financial experts quoted by Allgas Energy would suggest otherwise. The Commission considers that it needs to be made more explicit that there is no single correct method to calculate a rate of return and there can be a range of plausible values used in applying a method. It is recommended that s.8.31 be reworded to reflect this.

RECOMMENDATION 7.9

To ensure regulators are given clear guidance about the uncertainty associated with calculating an ex ante regulatory rate of return, s.8.31 of the Gas Code should be changed to the following:

s.8.31 If a Rate of Return is used in determining a Reference Tariff then the method used to calculate the Rate of Return and the values used in applying that method shall in the first instance be proposed by the Service Provider. In assessing the Service Provider's proposal the Relevant Regulator must take account of the fact that there is no single correct method to determine a Rate of Return and there is often a range of plausible estimates that could be used in applying a Rate of Return method. The role of the Relevant Regulator is therefore to assess whether the Service Provider's:

(a) proposed method has a plausible conceptual basis; and

(b) values used in applying the method lie within the range of plausible estimates.

The Relevant Regulator must approve the proposed method if (a) is satisfied. The Relevant Regulator must approve the values used in applying a method if (b) is satisfied.

In addition, s.8.30 should be amended so that, consistent with recommendation 7.5, non building block methods are allowed in certain circumstances; and, consistent with s.8.1(a)(ii) of the recommended pricing principles (recommendation 7.1), regulatory risk is recognised in setting an *ex ante* regulatory rate of return.

RECOMMENDATION 7.10

To ensure that the Gas Code is consistent with recommendations 7.1 and 7.5, s.8.30 of the Gas Code should be changed to the following:

s.8.30 If a Rate of Return is used in determining a Reference Tariff then the Rate of Return should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service including that resulting from regulation).

International comparison of rates of return in regulated industries

The ACCC commissioned National Economic Research Associates (NERA) to compare declared post-tax regulatory rates of return across various jurisdictions and industries in the United Kingdom and North America. NERA (2001) concluded that:

> … Australian regulators appear to offer approximately the same or higher returns than North American regulators who in turn appear to offer significantly higher rates of return than in the United Kingdom. (NERA 2001, p. 2)

NERA (2001) acknowledged that there are a range of technical issues that can make international comparisons difficult. Nevertheless, it claimed that there was no strong reason why its ranking would change.

However, NERA's findings were disputed by the NECG in a paper produced with the support of businesses operating in Australian regulated industries:

> Our results show that WACC allowances in Australia are not generous in international terms, and certainly not excessively so. The results do not support the assertions of the ACCC that returns compare favourably with those in the UK and US, especially if these decisions are seen in relation to approaches to asset valuation and the overall level of uncertainty in the WACC in Australia and overseas. (sub. 56, p. 101)

This conclusion was based on an analysis of over 100 regulated decisions in Australia, the United States, the United Kingdom, Canada, France, Ireland, the Netherlands and New Zealand in the airports, electricity, gas, rail, telecommunications and water sectors.

The ACCC made a supplementary submission in which it questioned the accuracy of the NECG's results:

> The methodology applied by NECG is subject to a number of questionable assumptions that lead to concerns about the validity of the results presented. In particular, the NECG results may overstate the comparable level of return provided in overseas regulatory decisions. (sub. 72, p. vii)

The NECG responded:

> In our opinion, the ACCC's critique of the methodology employed in the NECG study does not stand up to close scrutiny. The ACCC has not demonstrated the assumptions adopted by NECG are inappropriate. It also has not demonstrated that an alternative approach would provide fundamentally different conclusions and be preferable. (sub. DR97, p. 29)

This debate highlights the fact that regulatory rates of return are set on the basis of many assumptions. Such assumptions are used because regulation is applied in a world of uncertainty. This uncertainty cannot be removed by requesting more information from service providers, or by hiring consultants to undertake studies.

FINDING 7.5

There is disagreement among technical experts about how regulatory rates of return (WACC) in Australia compare to those in other countries. This illustrates the inevitable imprecision and subjectivity that occurs when regulators are required to approve reference tariffs.

Given the complex technical issues involved with regulatory rates of return and their relevance to more than just gas pipelines (for example, telecommunications and electricity regulation), the Commission considers that a separate study should be undertaken by a group of experts to examine the issues.

RECOMMENDATION 7.11

A study should be undertaken by a group of recognised experts in the field of financial economics that considers whether a robust method can be developed for setting businesses' expected rate of return on capital under incentive regulation. This should include a review of the use of the capital asset pricing model by Australian regulators.

7.6 Use of competitive tenders to set reference tariffs

The Gas Code provides for the use of competitive tenders as a mechanism to set reference tariffs for proposed pipelines (box 7.10). This is an alternative to the building block approach described earlier in this chapter.

The rationale for using a competitive tender to set reference tariffs for a new pipeline is that competition for the market is a good proxy for competition in the market. Thus, a competitive tender can in principle be a substitute for costly building block determinations of reference tariffs. The ACCC (sub. 48, p. 63) noted that a potential advantage of this approach is that it mitigates the 'perceived regulatory risk' associated with regulator discretion in determining reference tariff parameters.

Participants' views

Despite the potential advantages of competitive tenders, a range of participants claimed the tenders conducted under the provisions of the Gas Code had delivered unsatisfactory outcomes. The AGA (sub. 13, p. 61) noted that no gas distribution projects have been completed for which a Gas Code compliant competitive tendering process had been conducted, with seven proposed projects since 1999 having been deferred or shelved. The ACCC (sub. 48, p. 103) also noted that some of the competitive tenders conducted under the Gas Code have led to unsatisfactory outcomes.

Box 7.10 **Competitive tenders for setting reference tariffs**

Under s.3.21 of the Gas Code, any person may conduct a competitive tender to determine reference tariffs for a new pipeline. The person conducting a tender must first submit a 'tender approval request' to the relevant regulator to have the proposed tender process approved. Before granting approval for the tender process, the relevant regulator must be satisfied, among other things, that a successful tenderer will be selected principally on the basis that the tender will deliver the lowest sustainable tariffs to users generally over the life of the proposed pipeline (s.3.28 (f)(i)).

Once the successful tender has been selected, the outcome must be submitted for final approval by the regulator. To grant this approval, the regulator must be satisfied that the proposed tender process was followed, and the successful tenderer was selected in accordance with the selection criteria (s.3.33).

If final approval is granted, then the pipeline becomes a covered pipeline under the Gas Code (s.3.34) and the terms and conditions of access (including the reference tariffs) proposed by the successful tenderer will apply. Within 90 days of the regulator approving the tender outcome, the successful tenderer must submit an access arrangement that includes these terms and conditions and those items not determined through the tender process (s.2.2).

Participants noted a number of deficiencies with the Gas Code's competitive tendering provisions. One deficiency was the difficulty of satisfying some of the competitive tendering requirements. In this regard, the Tasmanian Government highlighted its experience in seeking to conduct a Gas-Code compliant competitive tender for gas distribution and retail franchises. The Tasmanian Government considered it was difficult to ensure the tender process led to reference tariffs that were the lowest sustainable (s.3.28(f)(i)) and satisfied the objectives in s.8.1 of the Gas Code:

> During the tender process, it became apparent that satisfying the requirements of the [Gas] Code was highly unlikely. In particular, section 8.1 of the Code, detailing general principles for establishing reference tariffs, was very difficult to satisfy, and proved to be open to subjective interpretation by the local regulator. Furthermore, the requirements of section 8.1, together with other parts of the Code, such as section 3.28(f)(i) and section 3.33(c), constrained the flexibility in pricing considered necessary to stimulate the market development required to provide an economic return on infrastructure investment over the project life. (sub. 45, p. 8)

Participants also claimed that the focus of the competitive tender provisions on the lowest cost bid, combined with the high costs of tendering, impacted on the viability of projects and acted as a deterrent to prospective service providers:

> Two … core weaknesses of the existing competitive tender arrangements are a restrictive focus on the lowest cost service provision and the high costs of tenders which due to the requirement of some local government authorities for recovery of tender costs against the successful tenderer, may significantly impact on the economic viability of the project. (AGA, sub. 13, p. 60; TXU Australia, sub. 11, p. 8)
>
> In relation to greenfields projects, the high cost of competitive tenders (e.g. surveying, engineering and forecasting), load risks, regulatory uncertainty and the focus on the lowest cost bid makes such projects unattractive from the tendering service providers' perspective. This explains why no competitive tender for a greenfields distribution project has progressed past the tender phase. (Envestra, sub. 22, p. 37)

The Tasmanian Government noted that focusing on the lowest cost bid (sustainable tariff) could be inappropriate when expected returns on investment are low (possibly zero), and other criteria should be given primary consideration:

> Under these circumstances, network coverage and timing of the network rollout become more important assessment/selection criteria than network tariffs. The Tasmanian experience also highlights the [Gas] Code's failure to recognise the complex tradeoffs that exist between the coverage, speed of rollout and access prices. (sub. 45, p. 8)

Some participants also noted areas where the current competitive tendering provisions lacked flexibility. ExxonMobil noted that once the regulator had approved the tender process, the current provisions did not allow a pipeline's specifications to be reoptimised:

> The tender process effectively fixes the pipeline route and markets with little flexibility in these arrangements. However, ongoing project development as real market opportunities are firmed up may require the pipeline design to be re-optimised regarding capacity and potentially its route. (sub. 8, p. 5)

The ACCC (sub. 48, pp. 103–4) also noted that the Gas Code's competitive tender provisions did not allow:

- a person submitting a tender approval request to make even minor changes prior to it being approved by the regulator (or allow the regulator to require changes prior to approval)
- a person simultaneously tendering for both a transmission and distribution system to have the tender process considered by a single regulator
- explicitly for conditional bids to be submitted and for a ranking of suitable bids, rather than just the selection of a single winning bid.

While some of the identified deficiencies might have contributed to the unsatisfactory outcomes under the Gas Code's competitive tendering provisions, various participants noted other factors that might have contributed to these outcomes.

The ACCC claimed that the unsatisfactory outcomes were a result of the provisions being used in circumstances where projects were marginal:

> … some tenders run under the auspices of the [Gas] Code have led to unsatisfactory outcomes. However, it appears that the principal problem in several of these tenders was a lack of commercial viability of the underlying project. This may have been due to the marginal nature of some of these proposals. (sub. 48, p. 103)

The ACCC also suggested that the competitive tender conducted by the Tasmanian Government under the auspices of the Gas Code might have failed because of additional requirements in the tender process (above those in the Gas Code). For example:

> A mandatory requirement of the tender process was that as part of its submission, a bidder was required to make an irrevocable offer to enter into an agreement to purchase the Launceston town gas distribution system 'at a fair and reasonable price determined by an independent valuer'. (sub. 48, p. 101)

The Tasmanian Government implied that the shortcomings in the Natural Gas Pipelines Access Agreement franchising principles influenced the outcome of the competitive tender process:

> The failure of … [the Gas] Code compliant tender process [in Tasmania] to attract adequate bids to secure the non-renewable, short-term franchises for gas distribution and retailing that were available in Tasmania under the terms of the NGPAA [Natural Gas Pipelines Access Agreement], illustrates the shortcomings of the current franchising principles. (sub. 45, p. 7)

Some participants suggested amendments to the current competitive tender provisions in the Gas Code. For example, the AGA suggested that the existing competitive tender provisions should be substantially redrafted:

> Key changes which may assist the more effective functioning of the tender provisions include:
>
> - revising the [Gas] Code's unbalanced focus on the lowest sustainable tariff as a core criteria for bid assessment (s.3.28 (f)(i));
> - streamlining of the Code tender approval process to avoid unnecessary delays;
> - allowing scope for integration of Code tender and public subsidy processes to avoid duplication and/or tender failures. (sub. 13, p. 67)

The ACCC also noted:

> … there is scope to simplify the competitive tender process under the [Gas] Code and also to develop other means of dealing with issues where people have tried to use the competitive tender process in the past, where there might be better approaches that could be utilised. (trans., p. 326)

The Commission's assessment

It appears that none of the competitive tenders conducted under the auspices of the Gas Code have resulted in the construction of a distribution network or transmission pipeline. Factors that might have contributed to this include projects lacking underlying commercial viability and the restrictive nature of exclusive franchising arrangements.

Deficiencies with the Gas Code's competitive tendering provisions also seem to be a factor. In particular, these provisions appear to be inflexible, costly and time consuming; and the focus on the lowest cost bid might not be appropriate for some projects where other considerations are important, such as the timing of a distribution network's rollout. Therefore, the Commission considers that the Gas Code's competitive tendering provisions require amendments to make them more flexible and less costly.

The competitive tendering provisions will also need to be amended to ensure they are consistent with the Commission's recommended pricing principles (recommendation 7.1). In particular, s.3.33(c)(ii) of the Gas Code requires:

> … that the Reference Tariffs determined in accordance with the tender process … contain or reflect an allocation of costs between Services and an allocation of costs between Users which is fair and reasonable.

This introduces an objective that is not in the pricing principles and could conflict with those principles.

FINDING 7.6

Simplifying the Gas Code's competitive tendering provisions would make them more flexible and less costly. For example, the tender approval process could be streamlined by allowing a person simultaneously tendering for both a transmission and distribution system to have the tender process considered by a single regulator.

7.7 Detailed information requirements

Regulators have significant powers under the Gas Code to collect information. Service providers must provide at least six categories of access arrangement information to the regulator when submitting an access arrangement for approval (box 7.11). The current Gas Code states that the information must (in the regulator's opinion) adequately enable users to understand how each of the elements of an access arrangement was derived (including reference tariffs), and to form an opinion on whether the access arrangement complies with the Gas Code (s.2.6). If a regulator considers the information is not adequate, then it can request that the service provider amends and resubmits the information (s.2.9).

In addition, s.41 of schedule 1 to the *Gas Pipelines Access Act* gives the relevant regulator powers to obtain particular information and documents that might assist it in the performance of its duties. Sections 4.1 and 4.2 of the Gas Code also state that service providers must establish and maintain certain accounts, and that regulators can publish guidelines on how these accounts should be prepared.

Participants' views

The Gas Code's information requirements impose compliance costs on service providers, since they are required to keep information that might otherwise not be maintained as part of standard business practice. Nevertheless, some participants considered that the current information requirements need to be strengthened. For example, the Hunter Gas Users Group claimed:

> … transparency and information disclosure are the only sure way of protecting gas users' interests and rather than weakening the [Gas] Code provisions, we strongly consider that the Code should be strengthened … (sub. 4, p. 7)

Similarly, the Energy Markets Reform Forum argued:

> … there are important improvements necessary to rebalance the interests of the stakeholders. In particular, the EMRF [Energy Markets Reform Forum] emphasises the resource and information asymmetry problems faced by users (as well as regulators). These imbalances would not be addressed by rolling-back or diluting the key provisions of the national Gas Code (e.g. information disclosures in particular) but actually strengthening them. (sub. 30, pp. 15–16)

As already noted, under s.41 of the *Gas Pipelines Access Act*, a regulator has powers to obtain information and documents that might assist in the performance of its duties. Where the person providing the information states that it is confidential or commercially sensitive, s.42 outlines the procedures that regulators must follow if they want to disclose this information and s.43 outlines a service provider's right to appeal this disclosure.

Box 7.11 **Information disclosure requirements**

As part of the approval process for an access arrangement, the following 'access arrangement information' must be submitted to the relevant regulator. The specific items listed under each category are the examples given in attachment A of the Gas Code. This information may be categorised or aggregated to ensure that the disclosure of the information is not harmful (in the regulator's opinion) to the business interests of a service provider or users. This does not limit the regulator's ability to request information in an uncategorised or unaggregated form.

Category 1: Information regarding access and pricing principles

- Tariff determination method
- Cost allocation approach
- Incentive structures

Category 2: Information regarding capital costs

- Asset values for each pricing zone, service or category of asset
- Information as to asset valuation methods — historical cost or asset valuation
- Assumptions on economic life of asset for depreciation
- Depreciation and accumulated depreciation
- Committed capital works and capital investment
- Description of nature and justification for planned capital investment
- Rates of return — on equity and on debt
- Capital structure — debt/equity split assumed
- Equity returns assumed — variables used in derivation
- Debt costs assumed — variables used in derivation

Category 3: Information regarding operations and maintenance

- Fixed versus variable costs
- Cost allocation between zones, services or categories of asset and between regulated/unregulated
- Wages and salaries — by pricing zone, service or category of asset
- Cost of services by others including rental equipment
- Gas used in operations — unaccounted gas to be separated from compressor fuel
- Materials and supply
- Property taxes

Category 4: Information regarding overheads and marketing costs

- Total service provider costs at corporate level
- Allocation of costs between regulated/unregulated segments
- Allocation of costs between particular zones, services or categories of asset

Category 5: Information regarding system capacity and volume assumptions

- Description of system capabilities
- Map of piping system — pipe sizes, distances and maximum delivery capability
- Average daily and peak demand at 'city gates' defined by volume and pressure
- Total annual volume delivered — existing term and expected future volumes
- Annual volume across each pricing zone, service or category of asset
- System load profile by month in each pricing zone, service or category of asset
- Total number of customers in each pricing zone, service or category of asset

Category 6: Information regarding key performance indicators (KPIs)

- Industry KPIs used by the service provider to justify 'reasonably incurred' costs
- Service provider's KPIs for each pricing zone, service or category of asset

OffGAR (sub. 40, pp. 19–20) expressed concerns about these sections of the Act. It considered them to be:

- administratively complex and time consuming
- ambiguous in relation to the ability of regulators to disclose confidential information to advisers that are not employees of the regulator
- inconsistent with s.7.12 of the Gas Code (which allows the regulator to disclose information that a service provider states is confidential if it considers it would not be unduly harmful to the interests of a service provider or user).

Similarly, Worsley Alumina noted:

> … the Regulator's powers to obtain information and documents under the Gas Pipelines Access Law (GPA Law), which places the restriction on disclosure under sections 42 and 43 of the GPA Law, should be consistent with the restriction on disclosure under section 7.12 of the Gas Code. (sub. DR110, p. 17)

Participants also raised specific concerns about the power of regulators to compel service providers to provide and/or maintain information. While regulators have some powers in this regard (under ss4.1–4.2 of the Gas Code), there were concerns about the ambiguity associated with these powers. For example, BHP Billiton claimed:

> While the [Gas] Code provides the regulators with some power to issue 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 [Gas Pipelines Access] Law permit the regulator to require the regulated businesses to provide the prescribed information during the regulatory period. (sub. 26, p. 120)

In particular, OffGAR (sub. 40, pp. 20–1) claimed there is ambiguity regarding the power of regulators to compel service providers to keep and maintain:

- information that would enable an assessment on the reasonableness of cost allocations between:
  - regulated and unregulated parts of a business
  - customer classes and services
- nonfinancial information on operating and technical matters, such as information that might be required for effective benchmarking purposes, or information not directly required for accounting purposes, such as forecasts
- information that would enable an assessment on the reasonableness of costs attributable to activities undertaken under service agreements and contractual arrangements with associated businesses (this issue is examined further in chapter 10).

OffGAR (sub. 40, p. 21) also claimed that regulators have no powers to compel service providers to keep and maintain information on service quality.

OffGAR wanted its powers extended to enable it to access relevant information in between access arrangement reviews. It wanted these powers to ensure that service providers keep and maintain information in an appropriate way:

> Regulators do not have the power to require reporting of information by service providers in periods between times of review of access arrangements, limiting the ability of regulators to identify any problems with the information being maintained until an access arrangement review process has commenced. (sub. 40, p. 21)

The National Gas Pipelines Advisory Committee (NGPAC) Secretariat (sub. 34) also noted that regulators have raised the issue of the inadequacy of information collection powers (outside of those available at the time of an access arrangement review), and have attempted to have the Gas Code amended through the NGPAC process. The NGPAC Secretariat noted the outcome of this process:

> … NGPAC agreed that it would not support a new unbounded information gathering power for regulators and that the project team should prepare a paper that explored the alternatives. This paper was considered by the jurisdictions, and agreed to the preparation of a draft information memorandum for a more bounded [Gas] Code change.
>
> Finally, at the meeting of 4 April 2003, NGPAC considered the draft but, given the proximity of a major review of the [Gas] Code/Law, agreed not to progress the issue at this point but to refer the issue to the major review. (sub. 34, p. 36)

The AGA noted that regulators' claims regarding the need for information collection powers to be expanded have not been substantiated, and this is why NGPAC did not approve the proposed amendments to the Gas Code:

> Following the failure by regulatory authorities supporting expanded information collection powers to identify additional types of information they might require, but were unable to collect, a majority of members of NGPAC agreed at a meeting on 20 March 2002 that regulators had not made a case for new or expanded information powers.
>
> This position was reaffirmed by the decision of NGPAC to reject another regulator-sponsored [Gas] Code amendment proposal expanding information collection powers in April 2003 and remove the item from NGPAC's agenda. This decision was supported by all Australian government representatives, except South Australia. (sub. 68, p. 18)

Other participants (generally service providers) also argued against strengthening the Gas Code's information requirements or regulators' powers in this regard. They claimed that the current requirements are heavy-handed, intrusive and have imposed unnecessary costs on regulated service providers:

> The application of the Gas Access Regime has … gradually transformed the regime into one based on … high levels of prescriptive information gathering from regulatory authorities, extending to information irrelevant to the establishment of default tariffs. (Alinta/Multinet, sub. 36, pp. 5–6)

> Obviously greater information requirements will only mean more complexity, intrusion and a consequential level of increasingly detailed decision making amounting to ‘centrally planned’ or ‘virtually nationalised’ economic regulatory control. This is already in evidence, clearly indicating that the Gas Code is already too intrusive, burdensome and heavy handed. (Goldfields Gas Transmission, sub. 18, pp. 13–14)

> The information gathering provisions of the Gas Access Regime are expansive and their application by regulatory authorities have in many circumstances resulted in unnecessary costs to regulated gas businesses. Information gathering costs are particularly high under the heavy-handed forms of cost-based access pricing applied by existing regulators. (AGA, sub. 13, p. 95)

APIA expressed specific concerns regarding regulators’ accounting guidelines published under s.4.2 of the Gas Code:

> Regulators have added unnecessary complexity and interference in the commercial operations of pipeline businesses through requiring the adoption of a regulator approved or published accounting guidelines as provided for in section 4.2. … Through these guidelines, regulators are able to prescribe a method of collection and allocation of shared costs in an arbitrary manner, which need not correlate with the way the business is operated and is not the same way the service provider would allocate costs in an access arrangement. (sub. 44, pp. 81–2)

In addition, some participants claimed that the current information requirements and powers were already sufficient to enable regulators to assess access arrangements and questioned the benefits of extending the requirements of the regime:

> Under … [the] combined provisions regulatory authorities have, or can obtain, all of the relevant information required to assess proposed access arrangements or monitor compliance with the [Gas] Code. (AGA, sub. 13, p. 95)

> If regulators were to have their way, this paper burden would become more onerous, as regulators are proposing that service providers be required to maintain regulatory accounts. It is noted that both the ACCC and the QCA [Queensland Competition Authority] are proposing to impose the collection of such information. Given that operating costs comprise such a relatively small proportion of the overall costs of transmission pipelines, Epic Energy questions what benefits are to be achieved from such a course of action. (Epic Energy, sub. 37 , p. 64)

The AGA (sub. 13, p. 95) also expressed concerns about the tendency and the legitimacy of regulators’ increasing reliance on the ‘effectively unbounded information collection obligations contained under State-based operating licence regimes’, given the current requirements in the Gas Access Regime. One example is the ESC’s power to obtain information from Victorian gas distributors through its administration of distribution licences. An illustration of this is s.12 of the 2001 new area gas distribution licence for Envestra, which stated:

> … 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. (ORG 2001, p. 6)

However, this is not the case in all States. For example, in Western Australia, s.51 part 6 of the *Economic Regulation Authority Act 2003* prohibits the regulator from using its State-based powers to fulfil its role under the Gas Code.

The Commission's assessment

If the building block approach is seen as necessary, then there seems to be limited scope to reduce the information requirements for service providers, given that regulators need a significant level of information to fulfil their obligations.

In addition, it appears the Gas Code needs to be amended to enable regulators to obtain information that would assist in substantiating the cost allocations used to determine the total cost (revenue requirement) of providing all reference services in aggregate. At the time of an access arrangement review, costs might need to be allocated across:

- regulated and unregulated business entities, such as costs of a parent company shared by a retailer and a service provider
- separate regulated assets, such as the overhead costs of a service provider that owns two regulated networks in different jurisdictions

Cost allocations are based on forecasts of certain variables. It would assist regulators in assessing the forecast variables used to allocate costs if they had access to historical information on these variables. Therefore, the Commission proposes that service providers maintain information throughout an access arrangement period on the variables used to allocate costs. This might require a service provider to maintain information that a parent company would provide on variables used to allocate costs to regulated and unregulated business entities. At the time of a review, the regulator could examine the historical information to help it assess the cost allocations proposed for the subsequent access arrangement. However, the Commission considers that this proposal should be designed so it does not limit the use of different cost allocation methods in a subsequent access arrangement period.

RECOMMENDATION 7.12

To enable regulators to assess the cost allocations used to determine a service provider's total revenue, a new clause should be inserted in s.7 of the Gas Code as follows:

- ***During the Access Arrangement Period the Service Provider should collect and maintain data on the variables used as the basis of cost allocations for the purpose of deriving Total Revenue.***

However, the Commission recognises that information requirements are not costless. Therefore, given that the Commission has recommended deleting sections of the Gas Code that require costs to be allocated between individual reference services and users (consistent with recommendation 7.1), it is necessary to modify the sections of the Gas Code relating to detailed information requirements that require provision of information on these cost allocations.

RECOMMENDATION 7.13

The Gas Code should be amended so that the information that service providers are required to provide under ss2.6–2.7 and attachment A does not include information on cost allocations between different reference services (where there is more than one) or between users.

The Commission also does not consider that information collection powers should be extended to compel service providers to maintain other information, such as on service quality. Under the Gas Access Regime, regulators do not appear to have powers to enforce particular service quality standards. Therefore, there would be little benefit in collecting this information. In addition, service quality is often monitored under licence provisions. For example, in Victoria, the ESC has issued the gas industry guideline number five which:

> … was commenced by the [ESC] … to detail service standards and targets for gas businesses to report periodically to the … [ESC], to enable [it] … to achieve more efficient and effective performance monitoring. The guideline was converted into an information specification: gas industry performance indicators information specification … as a result of the public consultation process on the guideline. (ESC 2004b)

The Commission also does not consider that the benefits of allowing regulators to obtain information between access arrangement reviews would be greater than the costs on service providers. This is consistent with the current design of the Gas Code, where the role of regulators is to vet proposed access arrangements that, once approved, generally remain in force until the end of the access arrangement period.

Also the onus should be on regulators to minimise the costs of information requirements where possible.

FINDING 7.7

Regulators are currently seeking to have their powers under the Gas Access Regime extended so they can obtain information between access arrangement reviews. This extension has the potential to add unnecessarily to service providers' compliance costs.

In relation to OffGAR's comments on ss42–43 of the *Gas Pipelines Access Act*, the Commission considers that, while the procedures might be time consuming, they are appropriate to protect the rights of service providers in relation to confidential or commercially sensitive information. The Commission does not endorse any weakening of these procedures.

The Commission is concerned that regulators could use State-based powers to obtain information (beyond that specified in the Gas Access Regime) for the purposes of approving a service provider's access arrangement. This approach lacks transparency, could impose unwarranted costs and lead to inconsistencies in the information requirements placed on service providers by regulators across different jurisdictions.

FINDING 7.8

There is scope for some regulators to use State-based powers to obtain information from regulated distributors that is beyond what is specified in the Gas Access Regime. This could impose unwarranted costs and lead to inconsistencies in the information requirements on service providers across jurisdictions.

RECOMMENDATION 7.14

To ensure that regulators cannot use State-based powers to access information beyond that specified in the Gas Access Regime, a new clause should be inserted into s.7 of the Gas Code as follows:

- ***The Relevant Regulator for the purposes of approving a Service Provider's Access Arrangement can only use information collected under the information collection powers specified in the Gas Access Regime.***

7.8 Non price issues

Capacity management and trading

A capacity management policy outlines how the capacity of a gas pipeline will be allocated to different users, such as through bilateral contracts. Capacity trading occurs when a capacity right is traded between parties. Capacity management and trading is generally only relevant for transmission pipelines.

The Gas Code allows for two different models of capacity management:

- *Contract carriage* (used in all States and Territories except Victoria) — a service provider manages the pipeline's capacity by entering into bilateral contracts with shippers, usually made in advance on a long-term basis. Under these contracts, shippers have an exclusive right to the contracted capacity.
- *Market carriage* (used only in Victoria) — an independent system operator (VENCorp) manages the pipeline capacity through a 'poolco' approach. In Victoria, users can gain capacity rights through an authorised maximum daily quantity (AMDQ). These quantities were allocated based on existing contractual arrangements and historical usage (VENCorp 2003). Users can trade these quantities.

While different, the contract and market carriage approaches can, in principle, both achieve market clearing at minimum costs, as noted by Juris (1998):

> Two distinct trading models have been developed: a bilateral trading [contract carriage] model and a poolco model. Both models achieve market clearing at the minimum cost, though in different ways. The main differences between the models are in the nature of transactions and in the way the transactions are coordinated in natural gas and transportation markets. (Juris 1998, p. 24)

In addition, the structure of the pipeline system affects which model is more suited to a particular market. Juris (1998) noted:

> The structure of a pipeline system also affects the choice of trading model. Pipelines with a trunkline structure are ideal for the bilateral [contract carriage] model because network externalities are small. By contrast, a pipeline system structured as a dense network exhibits network externalities because loads in one line affect loads in another one. And since bilateral transactions do not take into account load interdependencies, market participants can require transportation services that do not minimise total transportation costs. In this case, then, the poolco model [market carriage] is more appropriate, because it allows the pipeline operator to determine the optimal gas flow schedule regardless of contractual paths. (Juris 1998, p. 27)

In Victoria, a poolco model might be more appropriate because the network is relatively dense, gas can flow in multiple directions and it is difficult to define capacity:

> The pool model [market carriage] … was implemented in Victoria because of the characteristics of the gas market. First, Victoria has a meshed pipeline network rather than a 'point to point' pipeline with multiple points of supply. The flow of gas on substantial sections of the principal transmission system can be bidirectional and gas flows are scheduled depending on supply and demand conditions at different nodes. As the network is interconnected and flows bidirectional, it is difficult to adequately define capacity, as is needed under a contract carriage model.
>
> Other characteristics of the Victorian market include a domestic demand profile that is highly sensitive to weather and unable to be met using line pack because of physical constraints. Market carriage and a spot market were argued as necessary to provide sufficient flexibility to meet daily swings in demand. (Short, Heaney and Burns 2003, p. 31)

Under either a contract or market carriage model, the trading of capacity can improve allocative efficiency. Trading of capacity enables it to be allocated to the purpose for which it is most highly valued, and improves the price signals for efficient capacity expansion (Alger and Toman 1990). In addition, capacity trading can reduce the ability of capacity holders (either users or service providers) to exert market power:

> The benefits of the resale market are maximised if any potential market power is effectively checked. Competition among sellers automatically provides one check on market power. For most segments of most pipelines, we would expect that many potential sellers are available to compete. Anyone with a service agreement could resell some capacity. (Alger and Toman 1990, p. 268)

Contract carriage

If a covered pipeline is operated under a contract carriage model, then the service provider must have a trading policy that explains the rights of users to trade capacity. Under this policy, users of a pipeline must be able to transfer all or part of their contracted capacity. Depending on the circumstances, users might have to seek a service provider's permission to trade their capacity right.

On some of the pipelines operated under contract carriage, there appears to be unutilised contracted capacity. This was noted by WMC Resources:

> There are normally a number of shippers, quite often foundation shippers, which have contracted capacity that is unutilised. And you even get the bizarre situation where the shipper feels he has no surplus capacity yet he knows, on a day-to-day basis and even on a month-to-month and year-to-year basis, that part of that contracted capacity will not be used. (trans., p. 47)

There are potential benefits for shippers from trading their unutilised capacity. In particular, it enables shippers with long-term contracts for unutilised capacity to recover some of the costs:

> … if you have a long-term contract, there are quite often times where you've overcontracted, and you've had to contract for a long period, and capacity trading is one way to mitigate your costs there. (WMC Resources, trans., p. 42)

Despite the presence of unutilised capacity and the benefits of trading this capacity, the Council of Australian Governments Energy Market Review (EMR 2002, p. 196) observed that the 'Australian experience of capacity trading has been very limited'. Nevertheless, Short, Heaney and Burns (2003) noted:

> … short-term trading in both gas and transport does occur. For example, along the Moomba–Adelaide pipeline system, which is at capacity, the three shippers using the pipeline negotiate with each other in order to secure additional transport capacity at different times to suit their commercial requirements. (Short, Heaney and Burns 2003, p. 8)

There are a number of reasons why trading of unutilised capacity might not be occurring on some pipelines. First, there is a lack of information flow between shippers with unutilised capacity and potential users. This was noted by WMC Resources:

> … in general terms, people are able to trade unutilised capacity. It's really just a matter of matching needs and remembering you have different categories. … in general you are able to trade your capacity but it's not an honest market like the open-outcry market, it's one where you have to find someone who is interested and their needs fit yours. Quite often I think opportunities are lost because you are not sure who is available and who would be interested in the capacity. (trans., p. 47)

Second, the characteristics of end users on particular transmission pipelines might not facilitate capacity trading. That is, if there are only a few potential end users, all of whom want supply certainty, there might be very little scope to trade unutilised capacity:

> … obviously … [capacity trading] is something you would do on a transmission pipeline, but it depends on the end market. It's very difficult if you have got 10 customers to have someone trade capacity because there isn't that fluid market for someone to pick up spare capacity and use it for six months or one year. Generally it's an area where people want the certainty of having the capacity with a large capital-intensive investment — in a mine for example — they don't want to be just taking capacity for a year or so … (Goldfields Gas Transmission, trans., p. 62)

Short, Heaney and Burns (2003) also noted the lack of liquidity and transparency in the Australian gas market due to a limited number of market participants:

> These 'markets' are all characterised by a very limited number of players and, reflecting this lack of liquidity, a lack of transparency. The trades incur costs through

> extensive bilateral negotiations and contract arrangements. However, the lack of a sufficient number of market participants indicates that it is not appropriate for a broker to enter the market offering standard contracts, or posting prices or offering any of the services that a market maker would normally do that could decrease trading costs. The costs incurred in establishing a transparent market would not lead to lower overall costs given the limited number of market participants. Further, it may not offer additional benefits to the existing players, which could lead to insufficient revenues for any potential market maker. (Short, Heaney and Burns 2003, p. 40)

Third, shippers (operating in upstream and downstream markets) might be using their rights to capacity to undermine competition in these markets by preventing competitors from gaining access to capacity. A number of participants in this inquiry considered that the inability of new retailers to secure capacity rights is hindering the emergence of effective retail contestability:

> … overcontracting of capacity can be misused by upstream and downstream market participants to restrict competition. Such overcontracting is difficult to eliminate because there are valid reasons for precommitting to purchase pipeline capacity, for example, for planning purposes. (WMC Resources, sub. 43, p. 30)

> … the issues paper [for this inquiry] acknowledges that there is scope for pipeline access to be blocked by either an upstream or downstream party in order to prevent its competitors gaining access that would allow them to compete. Ergon Energy would agree that this practice causes a substantial barrier to entry for small retailers seeking to win customers and has significantly limited Ergon Energy's ability to compete in the major Queensland gas customer market. (Ergon Energy, sub. 7, pp. 1–2)

> Essentially, a new user [retailer] is … required to negotiate with an existing user (i.e., a competitor) for access to the MAP [Moomba–Adelaide pipeline], and hence the South Australian gas distribution network, for interruptible capacity only. … The current access arrangement on the MAP could restrict the opportunity to achieve benefits from gas full retail competition, including benefits to regional customers along the MAP. (South Australian Government, sub. 58, p. 7)

There are provisions in the Gas Code that should enable a user to access information on spare capacity, including another user's unutilised contracted capacity:

- A user with a marketable parcel of contracted capacity that is unutilised must provide information on this capacity to any person that requests it (s.5.8(a)). Such a user might also provide information on its unutilised contracted capacity to the service provider (s.5.8(b)).
- A service provider of a covered pipeline must establish and maintain a public register of spare capacity. The register must include information provided by a user under s.5.8(b) and information on any other spare capacity the service provider 'reasonably believes exists for delivery to defined points along the

> covered pipeline' (s.5.9). In the latter case, this includes capacity that is not contracted and contracted capacity that is unused.

There are penalties associated with breaches of these sections of the Gas Code. Western Power, which had trouble in accessing information on spare capacity for the Dampier–Bunbury pipeline, argued:

> … enforcement of these obligations, given that they are so important to the functioning of the Gas Access Regime, should rest with the regulator, upon receipt of a complaint from a user. (sub. DR115, p. 45)

However, there are no provisions in the Gas Code, that enable a regulator (or arbitrator) to compel a user to trade unutilised contracted capacity. According to the South Australian Government (sub. 58, p. 8), this approach 'gives a high weight to contract sanctity over provisions to mitigate capacity hoarding'.

Although a user might not be able to gain access to current unutilised contracted capacity, it can fund an expansion of the pipeline to gain this capacity (assuming the service provider agrees or an arbitrator requires the service provider to expand its pipeline (s.6.8(b)).

To overcome the problem of shippers using their capacity rights to undermine competition, a number of participants argued there should be provisions in the Gas Code that compel shippers to give up unutilised contracted capacity. For example, the South Australian Government stated:

> … the [Gas Access] Regime should provide disincentives for a user to contract for more capacity than is likely to be demanded by their customers. The regime should be changed, so that where spare physical capacity for gas exists, it should be capable of being required to be allocated to another user on fair and reasonable terms through a transparent arrangement. (sub. 58, p. 8)

In the draft report for this inquiry, the Commission requested participants' views on the possible implications of introducing use-it-or-lose-it rules for unutilised contracted capacity. The South Australian Government (sub. DR108) supported the introduction of such rules because it considered they would encourage users to trade their unutilised contracted capacity.

However, a number of other participants were strongly opposed to introduction of use-it-or-lose-it rules that would force a user to give up contracted capacity. For example, ExxonMobil noted it:

> … would strongly oppose any imposition of such a use-it-or-lose-it system as being counter to the development of free market solutions. ExxonMobil believes the regulated removal of a contracted right in such a manner significantly devalues the good planning and risk mitigation that firm rights provide. (sub. DR78, p. 7)

Other participants argued that introducing use-it-or-lose-it rules would undermine the use of foundation contracts to underwrite the construction of pipelines:

> One adverse implication of introducing a … ‘use-it-or-lose-it’ rule could be that foundation customers are discouraged about entering contracts because the on-sale of unutilised capacity from those contracts might be offered to other users and potential competitors at a price less than that paid by the foundation customer. (ERA, DR116, p. 18)

> Any proposal to confiscate third party underutilised contracted pipeline capacity rights could seriously jeopardise the viability of projects and operations. The ‘use it or lose it’ proposal … represents an attempt to confiscate property rights and could have devastating implications for users. This concern is compounded because of the take or pay nature of typical foundation contracts. … WMC believes the ‘use it or lose it’ policy regarding underutilised contracted pipeline capacity will undermine the value of foundation contracts as a means of underwriting pipeline investments. (WMC Resources, sub. DR99, p. 22)

> … such a mechanism could have potentially significant adverse consequences for the property rights of foundation users, possibly to the extent of adversely influencing future reliance upon the foundation contract mechanism which is generally needed in order for investment in pipeline infrastructure to proceed. (Goldfields Gas Transmission, sub. DR88, p. 23)

A number of participants provided other reasons why they considered use-it-or-lose-it rules were not warranted. Goldfields Gas Transmission noted that a user paying for unutilised contracted capacity would increase its cost of production, thereby making it easier for a potential competitor to enter the market:

> … under the [Gas] Code, other users who might not be able to gain access to current unutilised capacity, can fund an expansion of the pipeline to gain this capacity if none is otherwise available. Therefore, the Commission might like to consider that a current user who is paying for capacity in excess of current needs will presumably incur a higher cost of production in the market in which it is competing and hence will tend to provide the price signals, which are required in order for new market entrants to appear. (sub. DR88, p. 22)

Goldfields Gas Transmission also noted some constraints on introducing use-it-or-lose-it rules:

> - such a mechanism can only properly function in a market in which a sufficient degree of fluidity exists, that is the market must be sufficiently diverse and mature …
> - due to the inescapable laws of hydraulics, the redistribution of gas offtake along a pipeline can have marked effects upon its capacity to deliver gas at other points along its length and may necessitate expenditure in additional capacity (or make redundant investment which has already occurred) … (Goldfields Gas Transmission, sub. DR88, p. 23)

The ERA (sub. DR116) and ExxonMobil (sub. DR78) noted that unutilised contracted capacity can already be sold on an interruptible basis on some regulated transmission pipelines.

Further, the Gas Access Regime already provides a disincentive to capacity hoarding. Under schedule 1 s.13 of the *Gas Pipelines Access Act*, there are penalties for a service provider or any person (including those with contracted capacity) that prevents or hinders access to a service provided by a covered pipeline. In addition, any person can seek an injunction, declaratory relief or damages in relation to such conduct. One example given of the type of the conduct to which this section applies is 'refusing to sell a marketable parcel (within the meaning of the [Gas] Code) on reasonable terms and conditions' (footnote to s.13 of the *Gas Pipelines Access Act*). A marketable parcel includes all or part of a user's contracted capacity that the user reasonably expects it will not utilise.

Given all these factors, the benefits of introducing use-it-or-lose-it rules could be outweighed by the costs. Therefore, the Commission is not proposing that such rules be included in the Gas Access Regime.

Market carriage

The use of a market carriage system has the potential to overcome some of the problems associated with a contract carriage system. When end users are assigned AMDQs, full retail contestability is not hindered because allocated capacity moves with a user when it changes retailers.

Short, Heaney and Burns (2003) noted that in Victoria it is easier for a small retailer to enter the gas market. It also noted other advantages of the market carriage system, including greater transparency and access to information, and increased development of gas resources:

> … using a system operator means that transparency can be administratively created. In Victoria, a high level of market information is provided in addition to price data, as VENCorp is required to publish information such as gas demand and supply forecasts. This information allows market participants to make informed decisions about capital investments and developing market strategies.
>
> It has also been suggested that the existence of the market in Victoria can lead to the development of resources — for example, smaller gas fields whose developments are unlikely to influence gas prices, such as Yolla, could have been exploited even in the absence of long-term contracts. Because the field is so close to the Victorian market, production is economically viable as long as it can be delivered to the market for less than the current and expected future spot market prices. (Short, Heaney and Burns 2003, p. 31)

However, there could be disadvantages associated with the current market carriage system in Victoria, including that there are inadequate incentives for foundation customers to fund investment under the AMDQ system (VENCorp, sub. DR106, attachment 2, prepared by the Pipeline Investment Working Group).

The Institute of Public Affairs (sub. 2, p. 18) claimed there are significant disadvantages with the market carriage model in Victoria because shippers are unable to obtain firm carriage rights, and this had:

- contributed to the deferral of several gas fired power stations in Victoria
- created difficulties for businesses wanting to contract through the Victorian system to other systems.

On the other hand, the operator of the Victorian market carriage system (VENCorp, sub. 53, pp. 7–8) challenged the Institute of Public Affairs' claims, stating that:

- shippers can obtain rights to capacity by securing AMDQs (if necessary, through negotiating pipeline expansions with the owners)
- the main reason for the deferral of one of the gas fired power stations (Maryvale project) was because of the inability to contract gas supplies at affordable prices.

In addition, VENCorp claimed the market carriage system is enabling active capacity trading:

> … far from there being 'no user rights to capacity' and 'no possibility of capacity trading' under a market carriage regime, the Victorian arrangements do provide for capacity rights and, not only is capacity trading a 'possibility', such trading arrangements are in place and active. (sub. 53, p. 7)

VENCorp is currently undertaking an in-depth review of aspects of the Victorian market carriage system. This review was initiated in view of developments in the gas supply and pipeline infrastructure in Victoria, including gas fired power generation and interstate pipeline connections (VENCorp 2003). The review has been examining ways to improve the effectiveness of the market carriage system. Its recommendations are expected to be submitted to the Victorian Government at the end of June 2004.

Extensions and expansions policy

An access arrangement must include an extensions/expansions policy. This policy must specify how any extension or expansion of a covered pipeline will affect reference tariffs. For example, the policy might state that reference tariffs remain unchanged but a surcharge will be levied on incremental users. In addition, if a service provider agrees to fund an expansion under certain conditions, then the extensions/expansions policy must give a description of the type of expansion and the conditions under which the service provider will fund it.

An extensions/expansions policy must also specify the method for determining whether or not an extension or expansion will be treated as part of the covered pipeline for all purposes under the Gas Code. For example, the policy might specify that an extension will not be covered if the extension is not significant or that an expansion will not be covered unless the service provider nominates that it will be covered. The ACCC noted:

> A common approach by service providers to extension/expansion policies as part of proposed access arrangements has been that the service provider will nominate at the time of an extension/expansion whether or not it becomes part of the covered pipeline. (sub. 48, p. 95)

The ACCC (sub. 48) considered that as a pipeline reaches full capacity, the extensions/expansions policy should specify that all expansions (not relevant for extensions) will be treated as covered, unless the service provider nominates otherwise and the regulator agrees. The ACCC's reasoning was that a service provider can take advantage of the competitive tension between existing users and prospective users when capacity is constrained and impose unreasonable terms on users of the expanded capacity.

The ACCC (sub. 48) also claimed that even though access seekers can always apply for an expansion to be covered, this is not sufficient to deter service providers from imposing unreasonable terms. This is because users have no recourse to dispute resolution mechanisms or arbitration at the time of the negotiation if the capacity has yet to be constructed. Therefore, the ACCC (sub. 48, p. 96) claimed that amendments are required to 'clarify the Gas Code's ability to address the pricing of capacity expansions for covered pipelines'. In particular, the amendments should require all expansions of covered pipelines to be covered by default, unless the regulator agrees otherwise.

In addition, the Western Australian Government noted that if expansions were not covered by default, then cases might arise where an arbitrator is able to require an expansion of a covered pipeline, but cannot arbitrate on the terms and conditions of that expansion:

> … under the expansions/extensions policy in an access arrangement (s.3.16) it is possible that the expansion may not be covered by the [Gas] Code. Also, under the Code, the arbitrator has the ability to require an expansion of the capacity of the covered pipeline (s.6.22), and to deal with the costs of the expansion, including 'the cost of extending the pipeline' (s.6.15). There appears to be an inconsistency here in that:
>
> - the arbitrator could require that an expansion/extension take place; but

- that expansion/extension may not be covered under the Code; and therefore
- the arbitration provisions do not apply to that expansion/extension. (sub. 70, p. 14)

In the draft report for this inquiry, the Commission proposed that s.3.16 of the Gas Code be amended so that any expansion of a covered pipeline will be treated as part of the covered pipeline, unless the service provider nominates otherwise and the regulator agrees.

Participants had a range of views on this proposal. A number of participants considered that expansions should not be covered unless the Minister makes a coverage decision regarding the expansion. Various participants argued that the Australian Competition Tribunal's decision for the Moomba–Adelaide pipeline system (*Application by Epic Energy South Australia Pty Ltd* [2003] ACompT 5) (box 7.12) supported this view:

> Expansions should not be covered unless an application for coverage is made and consequent due process follows; that is, proper market analysis. This view is supported by the outcome of the Epic MAPS [Moomba–Adelaide pipeline system] appeal, where the Australian Competition Tribunal ruled against the ACCC's requirement that the Pelican Point expansion of the Moomba to Adelaide Pipeline be automatically 'covered'. (Envestra, DR82, p. 5)

> Epic Energy would be concerned if … [the draft recommendation that expansions of covered pipelines are automatically covered] were to be endorsed in the Commission's final report as it runs contrary to the approach adopted by the Australian Competition Tribunal in Epic Energy's challenge to the access arrangement for the Moomba to Adelaide Pipeline System. In that application, Epic Energy objected to a decision by the ACCC to require a particular expansion to be included as part of the covered pipeline. The Tribunal upheld Epic Energy's application in this respect, making it clear that coverage of expansions to an existing covered pipeline must be assessed on a case-by-case basis. To do otherwise perpetuates the current thinking of regulators and some stakeholders of a presumption of coverage. (Epic Energy, DR109, p. 22)

Further, APIA argued that coverage of pipeline expansions by default would distort pipeline investment:

> … [it] will create a bias in favour of new pipelines instead of expansions to existing pipelines on account of the former being exposed to less regulatory risk.
>
> In addition, … if implemented, [it] will entrench the current approach to pipeline expansion where pipeline owners are reluctant to expand in the absence of an expansion being completely underwritten by a contract from a customer. (DR100, pp. 51–2)

Box 7.12 **Australian Competition Tribunal's decision for the Moomba–Adelaide pipeline**

On 14 August 2002, Epic Energy South Australia Pty Ltd (Epic) filed an application to the Australian Competition Tribunal, under s.39(1) of the Gas Pipelines Access Law, for review of the ACCC's decision to draft and approve an access arrangement for the Moomba–Adelaide pipeline. In its application, Epic argued that the ACCC had erred in including the Pelican Point power station expansion as part of the covered pipeline. Inclusion of this expansion increased, for the purposes of determining the reference tariff, the pipeline's 'system primary capacity' from 323 to 348 terajoules per day.

The ACCC argued that any expansion in capacity of the covered pipeline (including the Pelican Point power station expansion) should be covered because Epic might be able to exercise market power. The ACCC relied exclusively on the existence of excess demand for the Moomba–Adelaide pipeline transmission services to support this conclusion. It argued that, given Epic might be able to exercise market power, coverage of the expansion would ensure that ss2.24(d)–2.24(f) of the Gas Code were satisfied.

In response, Epic argued that it could not exert market power during the access arrangement period as the Moomba–Adelaide pipeline was fully contracted until 2006. Further, the additional capacity of the Pelican Point power station expansion was contracted to 2019.

The ACCC sought to sustain its position by arguing that Epic could exert market power on interruptible services when the Pelican Point power station was not using its 'firm' transportation services. However, Epic Energy submitted that the current interruptible services on the Moomba–Adelaide pipeline were not reference services under the Gas Code and, therefore, it was inconsistent to argue the Pelican Point expansion be covered on the basis of the related interruptible service.

The Australian Competition Tribunal in its judgment found that the ACCC had erred in including the Pelican Point expansion as part of the covered pipeline. The Tribunal based its decision on a number of reasons including the following:

- The ACCC's reliance on excess demand as proof of Epic's ability to exert market power was flawed. First, there was uncertainty regarding the presence of excess demand. Second, the ACCC in assessing that Epic was able to exert market power had not considered other factors, such as the countervailing power of gas users.
- The potential for Epic to exert market power on the interruptible services associated with the Pelican Point expansion was limited because these services were only available on a random basis.
- The ACCC did not consider the service provider's legitimate business interests (s.2.24(a)). Coverage of the Pelican Point expansion would entail a significant reduction in the reference tariff because the proportional increase in capacity was greater than the proportional increase in costs. While not affecting revenue initially (as the pipeline was fully contracted) it would effect negotiations (and revenue) when existing contracts expired at the end of 2005.

Source: *Application by Epic Energy South Australia Pty Ltd* [2003] ACompT 5.

The ENA argued that default coverage of expansions does not recognise that the market conditions facing an expansion are different:

> Default coverage of system expansions and extensions fails to recognise the different market circumstances which a system expansion or extension faces compared to the original asset configuration. The assumption that any market power that may exist in an incumbent distribution network or capacity constrained pipeline will automatically apply in relation to a contestable network extension or additional spare capacity created through system expansion is unfounded. (sub. DR85, p. 16)

On the other hand, Worsley Alumina considered that default coverage of expansions was appropriate. Its rationale was that if a pipeline is covered because it has market power, then this market power will also exist on the expansion:

> … any expansion of a covered pipeline should always be treated as part of the covered pipeline, regardless of the service provider's nomination or preference to the contrary. Allowing nomination of an expansion to fall outside coverage runs counter to the concept that a pipeline is covered because it is judged to have market power and in all likelihood, market power would exist in relation to any capacity created as a result of an expansion. (sub. DR110, p. 18)

The Western Australian Government (sub. DR114, p. 2) also supported default coverage of expansions, arguing that it would 'improve clarity for service providers and users'.

The ERA considered that while the Commission's draft recommendation to introduce default coverage of expansions was worthwhile, it was contrary to the general approach taken for coverage decisions. It proposed that consistency might be achieved if, at the time of a coverage decision, a decision was also made on coverage of future expansions:

> While this draft recommendation runs counter to the general thrust for all coverage decisions to be made by an elected decision maker [currently the Minister] with NCC advice, in most if not all cases of progressive expansion of a pipeline system it could prove to be a worthwhile simplification of the [Gas] Code process. Greater consistency with other coverage arrangements might be achieved if this simplification were the default adopted unless specifically excluded as part of the original or a subsequent coverage decision. (sub. DR116, p. 10)

In relation to the Australian Competition Tribunal's decision for the Moomba–Adelaide pipeline, the ACCC argued that it did not imply that regulators should not in future draft and approve an access arrangement in which expansions were covered by default:

> … the ACCC notes that Mr Cribb of Epic Energy asserted that the [Australian Competition Tribunal] decision … should be interpreted against a presumption that expansions be regulated. While the Australian Competition Tribunal found that Pelican

> Point should not be covered, the ACCC is cautious about generalising this finding to all expansions.
>
> Section 3.16 of the [Gas] Code directs that an access arrangement must include a policy setting out how an extension or expansion will be treated. The ACCC notes that Epic originally appealed against the general expansions policy incorporated into the ACCC's final approval decision. However, immediately prior to the hearing, Epic indicated that it did not intend to pursue its application for review of this particular element of the final decision. Thus, the general application of s.3.16 has not been explicitly considered. (sub. DR119, p. 4)

The Commission's assessment

Prima facie, expansions of covered pipelines should be covered. If expansions of covered pipelines are not covered, a number of problems might emerge that would increase the uncertainty associated with the Gas Access Regime.

- The scope for regulatory error could increase because a service provider's reference tariffs would be based on the theoretical costs of a smaller pipeline (which excludes the uncovered expansion).
- The arbitration process could be undermined. An arbitrator could order the expansion of a pipeline but not be able to enforce terms and conditions on the expansion. In addition, it might mean that even if an expansion was built before a dispute, a service provider could maintain that all of the covered capacity was fully contracted and while the capacity associated with the expansion was spare, the arbitrator would have no power to enforce terms and conditions over this capacity.
- If a pipeline expansion generated economies of scale (that is, average costs fall), not covering the expansion means that over the long term a service provider could recover average revenue from reference services that is greater than the average costs of delivering these services.

Further, the Commission is not convinced that a case-by-case coverage assessment of expansion is warranted. It is ambiguous whether a person can apply for coverage of an expansion of an already covered pipeline. Under s.1 of the Gas Code, a person can apply for coverage of a pipeline or part of a pipeline. However, under previous coverage applications a part of a pipeline has been interpreted as a section between two geographical points. While this interpretation has not been tested through an application for coverage of an expansion, the italicised notes prior to s.1 suggest that a separate application for coverage of an expansion is possible:

> An extensions/expansions policy in the Access Arrangement for a Covered Pipeline will define when an extension to, or expansion of the Capacity of, a Covered Pipeline will be treated as part of the same Covered Pipeline and when that extension or

expansion is to be regarded as a separate Pipeline which may be the subject of a separate Coverage application.

It is difficult to see how a case could be made that the market power of a covered pipeline did not apply to an expansion of that pipeline. Under these circumstances, not covering an expansion by default has the potential to add to the administrative costs of the regime without increasing its benefits. If a service provider considers that the expansion has reduced its ability to exert market power in the relevant market, then the appropriate approach is to apply for revocation of the entire pipeline.

It is also unlikely that coverage of expansions by default will increase to a greater degree than a case-by-case assessment of expansions, the incentive to build expansions that are essentially fully contracted prior to construction. An uncovered expansion of an otherwise covered pipeline might still be subject to an application for coverage. Therefore, the incentive to build only to meet contracted demand would be similar under either approach.

The Commission also considers that the Australian Competition Tribunal's ruling that the Pelican Point power station expansion should not be covered does not solve any of the above-mentioned problems. It could increase the uncertainty associated with not, by default, covering expansions of otherwise covered pipelines.

Therefore, the Commission is of the view that expansions of covered pipelines should be covered by default under the Gas Access Regime. In the transition to this approach, where an expansion is currently not covered (such as for the Moomba–Adelaide pipeline), the Commission considers that, given the Tribunal decision, these expansions should remain uncovered until there is a successful coverage application.

RECOMMENDATION 7.15

Section 3.16 of the Gas Code should be amended so that it unambiguously clarifies that any expansion of a covered pipeline will also be covered.

7.9 Summing up

This chapter illustrates the many complex issues that regulators must consider when applying cost-based price regulation. It also illustrates how the Gas Access Regime requires regulators to make decisions on many matters where there is no single indisputable answer. For example, regulators have to decide whether a proposed *ex ante* regulatory rate of return is commensurate with the prevailing market for funds and risks faced by the service provider. In essence, regulators are placed in the difficult position of being expected to act as omniscient central planners.

Regulators have responded to the demanding requirements of the Gas Access Regime by requesting highly detailed information from service providers and by meticulously applying methods such as the CAPM framework. This is costly and creates a misleading impression of precision. In reality, regulators are making decisions under uncertainty and so must make a wide range of debateable assumptions. This uncertainty cannot be removed by requesting more information from service providers, or by hiring consultants to undertake studies. The reality is that businesses do not operate in a world of certainty. That is why investors demand a higher expected rate of return than they can obtain from a virtually riskless asset like government bonds.

This chapter highlighted a number of other problems with the current regulatory approach of having access arrangements with reference tariffs, including:

- high regulatory risk — service providers cannot be certain about the regulatory parameters and mechanisms that will be applied to their pipeline, despite the many pages of the Gas Code and the Gas Pipelines Access Law
- detailed information requirements are costly and intrusive
- increased complexity due to the apparent tendency of regulators to adjust regulatory depreciation to deal with deficiencies of the Gas Access Regime.

FINDING 7.9

There is high potential for regulatory error when approving reference tariffs. The Gas Access Regime requires regulators to make decisions about future market circumstances that are uncertain. This has led regulators to use many debatable assumptions. There is a consequential tendency for regulators to seek additional information from service providers and further studies by consultants. This is unlikely to reduce uncertainty significantly.

The Commission has made a number of recommendations on how to improve the cost-effectiveness of the regime's price regulation. In particular, it is recommended that pricing principles be included in the Gas Code that are similar to those adopted by the Australian Government for the national access regime. The Commission has also made various recommendations regarding specific sections of the existing Gas Code to ensure there is no inconsistency with the recommended pricing principles.

The recommended pricing principles would remove the requirement to allocate costs between different reference services (when there is more than one) and between users of a reference service. This would shift the focus of the regime's cost-based price regulation to the *total* cost of providing reference services in aggregate, rather than what should be the *average* cost of providing each reference service. The recommended pricing principles would also more directly address concerns about the current regulatory approach than would a reliance on concepts such as effective or workable competition.

In addition, the Commission has recommended the following:

- Allow service providers to use a non building block approach to determine the total cost of providing all reference services, provided the regulator is satisfied this would more likely meet the Gas Access Regime's objectives.
- Revise the rate of return provisions of the Gas Code so service providers have greater scope to choose among plausible methods, rather than being restricted to the CAPM approach.
- Clarify the information collection powers of regulators under the Gas Access Regime and the associated requirements imposed on service providers.
- Treat any expansion of a covered pipeline as part of the covered pipeline, so as to remove any ambiguity resulting from a recent decision by the Australian Competition Tribunal.

It is also highly desirable that actions be taken to reduce the regulatory risk faced by service providers. This issue is examined in detail in chapter 9 in the context of remedying the investment distorting effects of the Gas Access Regime.

While this report has made several recommendations to improve the cost-effectiveness of the current regulatory approach, the costs of this approach are likely to remain substantial, and so might outweigh the benefits for some covered pipelines. Therefore, it was recommended in chapter 6 that a light-handed form of regulation — not involving access arrangements with reference tariffs — should be applied to some covered pipelines. Chapter 8 considers what form of light-handed regulation would be applied to such pipelines.

FINDING 7.10

The current regulatory approach of cost-based price regulation is costly, especially in relation to the market impact. Therefore, while some refinements to the existing regulatory approach are needed, there is a sound basis also for an alternative less costly approach in certain circumstances that will generate larger net benefits.

8 Light-handed regulation

In this chapter, the case for using light-handed regulation for natural gas pipelines is outlined, and the form that such regulation could take is considered. In undertaking the analysis, the Productivity Commission has considered the regulatory models suggested by inquiry participants. It has also drawn on its experience in analysing price and access regulation in other industries, such as airports and harbour towage (PC 2001c, 2001d, 2001e, 2002a, 2002b).

8.1 The case for light-handed regulation

The analysis in earlier chapters indicates that there can be substantial costs under the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) as currently structured, that is, the current approach of prescribing reference tariffs and other matters in an access arrangement (box 8.1).

These costs arise from the intrusive cost-based price regulation applied under the Gas Access Regime. The regulation entails high compliance costs and inhibits commercial negotiations (chapters 3, 4 and 7). In chapter 7, the Commission concluded that it is possible to improve the cost-effectiveness of the current regulatory approach. Nevertheless, the costs of the current approach (access arrangements with reference tariffs) are likely to remain substantial and so might outweigh the benefits for some covered pipelines (chapter 4).

Some of these costs, particularly for users, can be less transparent than others. For example, in the short term, users benefit from low reference tariffs. However, if regulatory error leads to reference tariffs being set below efficient costs, then the longer term outcome will be declining service quality and inefficient investment to meet future demand. Regulatory error is a real possibility, given that the Gas Access Regime requires regulators to make decisions under uncertainty and has led to regulators using many debatable assumptions (chapter 7).

An additional concern is that the current regulatory approach is not well suited to the situation where there is emerging competition. As noted in chapter 2, the market conditions for gas transmission and distribution changed markedly in the past decade. This change is attributable to a range of factors, including the restructuring and privatisation of government owned enterprises in energy-related industries, the introduction of retail competition for gas and electricity, the deregulation of energy markets, and the formation of a national electricity market.

Box 8.1 Costs of the current Gas Access Regime

In other chapters of this report, the Commission found that the Gas Access Regime's regulatory approach of access arrangements with reference tariffs can be costly. The regime's costs are attributable to a range of factors, including:

- high compliance costs in the preparation of access arrangements (chapters 4 and 7)
- constraints on commercial negotiations (chapter 3)
- the high potential for regulatory error (chapters 4 and 7)
- high regulatory risk (chapters 4 and 7)
- the potential to distort or deter investment (chapter 4)
- changing the role of foundation customers through the inclusion of 'most favoured nation' clauses (chapter 4)
- difficulty in implementing in increasingly competitive markets (chapters 2 and 4)
- the benefit of intervening decreases as competition increases (chapter 4)
- limited guidance from economics about pricing in imperfectly competitive markets (chapter 4)
- regulatory gaming and lobbying (chapter 4)
- time delays (chapters 4 and 11)
- difficulty in applying regulation objectively (chapter 4)
- incentive for regulators to overregulate (chapters 4 and 7).

In response to these developments, competition has emerged between gas basins and pipelines to service specific markets, such as Adelaide and Sydney. Further, the gas transmission system in eastern Australia is increasingly interconnected. As a result, the traditional view of all gas pipelines as natural monopolies is becoming outdated. Emerging competition and the interconnection of networks have led to some 'contestable' and 'imperfectly competitive' markets in which two or more service providers can compete to supply gas. This trend makes the task of determining appropriate reference tariffs much more difficult.

As noted in chapter 4, the marginal benefit of intervening decreases as the gap between the 'efficient price' and the 'monopoly price' narrows. Thus, for pipelines that are not exerting substantial market power (that is, where the price gap is narrow), the marginal benefit of intervening is lower.

Further, chapter 4 notes that generally economics does not provide clear guidance on how to regulate prices in imperfectly competitive markets. In addition, the costs of regulatory error are likely to be greater when market conditions are changing, as is the case with the emerging competition among pipelines in Australia. As Viscusi, Vernon and Harrington (2000) noted, relying on market-based outcomes might be better than attempting to continually finetune regulation as a market changes:

> A policy of trying to finetune imperfectly competitive markets through price regulation is a perilous task that has been shown historically to be self defeating. A general policy of relying on unfettered competition seems advisable in markets that are not natural monopolies. (Viscusi, Vernon and Harrington 2000, p. 42)

Further, as noted by Professor Littlechild (sub. 24, p. 3), the costs of regulation in potentially competitive markets — in terms of 'getting it wrong' and discouraging investment — can be significant. Professor Littlechild identified gas distribution networks as an example of where such costs could be an issue.

The National Competition Council (NCC) observed that as markets become increasingly competitive, the level of regulatory intervention under the Gas Access Regime might need to become less interventionist:

> … it seems likely that as transmission pipeline infrastructure in Australia is developed, and more choices become available to gas producers, retailers and users, fewer pipelines will have substantial market power and the ability to profitably restrict competition in gas markets such that coverage under the Gas Code is appropriate. Further, as the culture of doing business in effectively competitive gas markets becomes entrenched, it may be appropriate to further lighten the level of regulatory intervention in the Gas Code. (sub. 57, p. 5)

Given that the current regulatory approach is costly and inappropriate when there is emerging competition, it is worthwhile considering whether a light-handed form of regulation could be applied to some covered pipelines (chapter 6).

The extent to which regulatory intervention is light-handed is determined by the:

- substantiveness of the variables the regulator attempts to control
- extent to which the regulator attempts to control the relevant variables
- compliance costs imposed on businesses.

In general, light-handed regulation places greater emphasis on encouraging commercial negotiations than on prescribing the terms of transactions between businesses and their customers, or imposing constraints on financial variables (such as a cap on prices, expected revenue or profits).

National Economic Research Associates (NERA), in a report prepared for the Victorian Essential Services Commission (ESC), characterised regulations tending towards the lighter handed end of the spectrum as those that might:

> … place less emphasis on reducing efficiency loss from prices being above costs (and so may involve greater rents), for the potential benefit of reducing administrative or other forms of efficiency loss arising through the conduct of regulation. (NERA 2004, p. 5)

As noted in earlier chapters, the current Gas Access Regime has not facilitated commercial negotiations. The services provided and prices charged under the current regime have largely been confined to the reference services and reference tariffs approved by regulators.

The potential advantages of light-handed regulation are that it:

- imposes lower compliance costs on regulated companies
- is less costly for regulators to implement
- reduces the scope for regulatory error to distort production and investment, given that there is less reliance on a regulator correctly prescribing prices and other conditions of commercial transactions
- reduces regulatory risk, since a company's financial performance is less dependent on how a regulator precisely implements particular rules
- makes businesses more responsive to changing market developments and more likely to innovate, because they are less constrained by the prescriptions of regulators
- reduces opportunities for regulatory gaming and lobbying, since there is greater emphasis on commercial negotiations, rather than prescriptive rules on prices and other conditions of commercial transactions
- enables users to negotiate terms and conditions that meet their unique circumstances, rather than be limited to those approved by a regulator
- provides for the phasing-in of deregulation as a market becomes increasingly competitive.

Framework for light-handed intervention

After deciding there is a case for light-handed regulation, it is desirable to identify and assess techniques for implementing light-handed access regulation.

There are various light-handed techniques that could be part of a framework for access to gas pipelines including:

- negotiate–arbitrate provisions
- monitoring and information disclosure
- regulatory undertakings
- pricing principles
- legacy pricing, performance-based regulation and total factor productivity
- threshold and control mechanisms.

Each technique is considered individually, though an optimal form of light-handed regulation might consist of a combination. In addition, ring fencing and provisions for anticompetitive conduct (not considered here) could also be included in a light-handed form of regulation.

There are a variety of ways in which the light-handed techniques could be implemented, including different institutional arrangements and different rules governing their application. At one end of the regulatory spectrum, these options could be designed with a high level of prescription, mandatory compliance and regulator intervention. At the other end, there could be little prescription, voluntary compliance and less intervention by a regulator. In summary, many of these techniques could be part of a heavy-handed or light-handed regime.

Negotiate–arbitrate provisions

Under negotiate–arbitrate provisions, access seekers are granted a legal right to negotiate the terms of access, with binding arbitration if negotiations end in dispute. In certain circumstances, an effectively designed negotiate–arbitrate framework can encourage commercial negotiation and innovation, and reduce regulatory compliance costs relative to the Gas Access Regime, while still providing a regulatory mechanism to prevent service providers from attempting to deny access to, or extract monopoly rents from, access seekers. For large users, there are benefits from greater flexibility in the terms and conditions of access that can be achieved through commercial negotiations.

However, the commercial negotiate–arbitrate framework also has a significant potential to revert back to an intrusive tariff setting regime through the arbitration process. This would occur if an arbitrator employs a ‘building block’ approach in deciding the appropriate tariff. Such an approach, in turn, would provide an incentive for the access seeker to initiate the arbitration process rather than engage in genuine commercial negotiations. BHP Billiton raised such a possibility:

> 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 … (sub. 26, p. 94)

Other drawbacks of the negotiate–arbitrate framework are the costs arising from the arbitration process (particularly in terms of timeliness of outcomes). For example, in chapter 4 the Commission notes that a generally available access arrangement for pipelines is likely to involve lower costs than requiring each access seeker to seek access through the negotiate–arbitrate framework. The Australian Competition and Consumer Commission (ACCC) drew on its experience with the use of negotiate–arbitrate models in the telecommunications industry to note:

> … arbitrations can be slow and costly. This reflects the unavoidably resource intensive and time consuming processes due to the complex nature of the issues and the need to conduct the hearing fairly. (sub. 48, p. 27)

The ESC (sub. DR112, p. 20) noted that a negotiate–arbitrate model is unlikely to be effective for gas distribution services and customers are 'typically small and less numerous than gas transmission customers and therefore have less countervailing market power'.

The negotiate–arbitrate framework involving a privately appointed arbitrator, proposed by the Australian Pipeline Industry Association (APIA) (sub. 44, pp. 78 and 89), might be useful as part of a light-handed regime. Commercial arbitration is likely to avoid the costs and delays associated with a costly building block approach because:

- the rules governing arbitration are those used in commercial circumstances (perhaps according to a commercial arbitration act and/or through an arbitration and mediation organisation)
- the incentives facing parties are different to those when the regulator is arbitrating according to a complex set of pricing principles.

Sharing arbitration costs between the parties can provide an incentive to reach commercial agreement.

Duke Energy International (sub. 21, p. 21) already maintains a commitment to a binding independent dispute resolution process as part of its nondiscriminatory access policy for uncovered pipelines. Under such a model, if the two parties cannot negotiate an outcome, they may appoint a private arbitrator to settle the dispute. The terms of the arbitration process and constitution of the arbitration panel would be a matter for the negotiating parties to determine.

Monitoring and information disclosure

There are various approaches to monitoring. For example, monitoring could entail information collection and reporting, information benchmarking, or key performance indicator monitoring. As with the negotiate–arbitrate framework, there is scope for variation in the light- or heavy-handedness of the framework. For example, the scope of monitored information can range from basic price, profit and/or cost information through to detailed information on a variety of quantitative and qualitative aspects of business operations. Similarly, there can be considerable differences in the actions that will be taken by regulators in response to observations and conclusions reached on the basis of the monitored information.

So whilst an effectively designed monitoring regime can offer significant improvements in economic efficiency, if these elements are not managed properly, monitoring has the potential to be ineffective at regulating behaviour at one extreme, and almost as intrusive as the current system at the other. It also has the potential to create regulatory uncertainty if there is a lack of clarity about the behaviour of companies that may trigger stricter more intrusive regulation.

New Zealand gas pipelines are subject to a monitoring regime. The regulatory regime for gas pipelines in New Zealand consists of a requirement for pipeline owners to disclose information regarding their financial and service quality performance and the threat of stricter regulation, such as the introduction of price control, if market power is abused.

The rationale for the light-handed regulation of gas and electricity networks in New Zealand was to place 'responsibility for access and pricing of line and pipeline facilities with market participants' allowing 'negotiations and agreements to take place without government involvement' (Ministry of Commerce 1995, p. 2). It was anticipated that the threat of general controls on anticompetitive behaviour under the *Commerce Act 1986* (New Zealand), and the threat of more heavy-handed regulation would be sufficient to overcome the incentive for pipeline owners to abuse their market power. The New Zealand regime is currently undergoing a review by the New Zealand Commerce Commission. It released a draft report in May 2004 (Commerce Commission 2004).

A number of Australian airports are also currently subject to a monitoring regime. The ACCC monitors prices, costs and profits at specified airports under s.27A of the *Prices Surveillance Act 1983*. The ACCC (2003d, 2004a) recently released price and quality of service monitoring reports for airports.

Airports under the monitoring regime are still subject to part IIIA of the *Trade Practices Act 1974*. In 2002, there was an application by Virgin Blue to have airside services at Sydney airport declared under part IIIA of the Trade Practices Act on the basis that Sydney Airport Corporation had the potential to increase charges under the regime, thereby reducing competition in the market for airline passenger transportation. In January 2004, the relevant Minister released his decision not to declare airside services at Sydney airport, consistent with the final recommendation of the NCC (2003a). The Minister was not satisfied that access to airside services through declaration would promote competition in a market other than for those services. In addition, the Minister was not satisfied that declaration would be in the public interest, because he considered that 'the potential benefits of declaration are outweighed by the costs of regulation' (Cameron 2004).

Light-handed monitoring might not necessarily restrain market power. The effectiveness of monitoring could be improved if there is a real threat of heavy-handed regulation at some later time. When effectively designed, a price monitoring regime promotes commercial negotiations and imposes lower compliance costs on service providers.

Regulatory undertakings

Regulatory undertakings are similar to regulatory determinations except the regulated entity voluntarily proposes the regulatory framework, and the regulator approves it. The current Gas Access Regime could be considered as a type of undertaking model, where the service provider proposes an access arrangement, that is approved by the regulator (chapter 3).

Other regulatory undertaking models give greater flexibility to the service provider to propose alternative regulatory models. Under part IIIA of the national access regime, for example, the regulator can approve an undertaking after consideration of a number of criteria (Trade Practices Act, s.44ZZA). The regulator's role is to assess whether the company's proposed terms adequately protect against the use of market power and promote the long-term interests of customers.

One benefit of the undertakings approach is the flexibility it gives service providers to use different methods to satisfy the regulatory goal. The ESC (sub. DR112, p. 17) noted that regulated companies have an ability to 'propose creative new regulatory methods' that might 'generate improved models that promote efficiency and better manage risk'. The regulatory undertaking approach also provides certainty (following regulatory approval) for the service provider and users over the access conditions that apply to the service in question.

A potential cost of regulatory undertakings is the relatively high upfront costs incurred in preparing an access arrangement. Another drawback is that the role of the regulator might be unclear and lack sufficient guidance. The framework therefore has the potential to be as intrusive as the current regime, for example, if the regulator undertakes an examination of the efficiency of costs and prices before approving the undertaking.

Further, where national consistency is a policy objective (as is the case under the Gas Access Regime) (chapter 3) the undertaking alternative may lead to several different regulatory arrangements, which could damage development of a national market for gas. At the time of implementing the Gas Access Regime, the Australian Government reported that a proliferation of individual regimes involving regulatory arrangements and institutions of varying quality was already occurring. The regime was introduced to bring some consistency to the arrangements (House of Representatives 1998, para. 33) (chapter 4).

One way to overcome the above problem of consistency is for the gas pipeline industry to propose a regulatory undertaking for approval under part IIIA. This would be similar to the National Electricity Access Code, an undertaking approved by the ACCC (2003a). Whilst requiring agreement from all service providers, this approach could be consistent with light-handed objectives. However, such an option for the Gas Access Regime could take considerable time and incur considerable costs. Arguably, it would take a long time to negotiate an undertaking agreed to by service providers and approved by the regulator (that would take into account the views of users and the wider economy).

Pricing principles

Pricing principles set out criteria to guide the way in which access prices might be determined. In the case of light-handed regulation, they could act as guiding, nonbinding principles. Under a heavy-handed regime, they could be mandatory principles to be adhered to.

Pricing principles have the potential to be a low cost way of providing flexibility in an access regime. In the case of the generic national access regime, flexibility is essential. It would be impractical to have more prescriptive requirements when the regulation can apply to a wide range of infrastructure services.

However, in the case of an industry-specific light-handed framework, the Commission has concerns that pricing principles might lack guidance for service providers, regulators and other interested parties. Further, the benefits of a pricing principles model could be undermined if there is a complaints mechanism in place that is relied upon by access seekers. As NERA noted:

> … in many cases [with negotiate–arbitrate provisions] parties have relied on arbitration rather than the preliminary negotiation process, and ultimately ended up in protracted debates about the scope and application of the price setting regime. (NERA 2004, p. 11)

Under the Gas Access Regime, it could be possible for pipelines regulated with light-handed regulation to refer to the pricing principles recommended in chapter 7. These pricing principles could influence the pricing of pipeline services, depending on how the light-handed regime is designed.

Legacy pricing, performance-based regulation and total factor productivity

Legacy pricing involves setting initial prices at historic levels (not necessarily with explicit cost justification) with adjustments in accordance with an index mechanism, such as a CPI-X formula (where CPI is the consumer price index and X is some measure of efficiency).

This might be considered a lighter handed form of intervention because once the historical starting price has been set, service providers do not have to undergo costly tariff reviews on an ongoing basis. It also avoids the problems associated with the detailed building block approach (chapter 7).

However, this form of intervention has a number of drawbacks, including that initial prices may not be efficient and these inefficiencies could become entrenched in the starting price. Moreover, it is still price regulation at the intrusive end of the regulatory spectrum (chapter 7). Under this approach, regulators retain a direct role in approving prices, regardless of which method is used to set prices.

Regulatory threshold and control schemes

The ESC has described regulatory threshold and control schemes as involving:

> … [the establishment of] a number of price, quality and/or profit thresholds …, as well as a process for periodically assessing firms' compliance with the thresholds. If the thresholds are breached, there is a more extensive investigation that could lead to formal price control. (sub. DR112, p. 19)

The approach has the advantage of a clearly articulated threat, and depending on how the regime is specified, it may not necessarily require costly price reviews.

However, the Commission has concerns that such a model might revert back to an intrusive tariff setting regime through the threshold setting process. It is not clear what principles are used to set the regulatory thresholds and whether they need to be approved by the regulator. Further, the regime relies on a clearly articulated process following a breach of the threshold, otherwise the regime may lack credibility (NERA 2004, p. 51).

The New Zealand Commerce Commission has implemented a threshold and control regulatory scheme for the New Zealand electricity transmission sector:

> The thresholds are a screening mechanism to identify lines businesses whose performance may warrant further investigation and, if required, control by the [Commerce] Commission. … The price path assessment criteria are consistent with a CPI−X price path … (Commerce Commission 2003, pp. 3–4)

NERA (2004) noted potential problems with the New Zealand regime. It considered that this regime could only be implemented in a heavy-handed fashion:

> The proposed framework can only function in the way it is intended if the [Commerce] Commission takes an active role in setting sophisticated, quantitative price and quality thresholds — that is, the framework cannot realistically be effective unless it is administered in a relative 'heavy-handed' fashion. (NERA 2004, p. 52)

Lighter handed gas regulation in other countries

There have been several overseas initiatives to either implement or consider lighter handed regulation of gas pipelines, with varying degrees of success. Examining the approaches to lighter handed regulation of third party access in overseas countries can provide insights into potential benefits and downfalls of different approaches. Box 8.2 summarises the lighter handed approaches to gas pipeline regulation in some countries. The case studies, like many of the frameworks identified above, reveal the importance of institutional arrangements and rules governing the application of lighter handed regulation.

Participants' views on light-handed regulation

Service providers tended to favour the adoption of light-handed regulation:

> The current form of regulation acts as a real and serious constraint on a company's willingness to invest in new facilities, and on their ability to maintain the investments they have made. Consequently, many operators of essential facilities are now seeking a return to a more light-handed regulatory framework — one that achieves the objectives of essential facility regulation, but at a greatly reduced cost to themselves, government and consumers. (Duke Energy International, sub. 61, p. 3)

> Since the first regulatory decisions under the Gas Access Regime made clear the heavy-handed and narrow manner in which the regime was capable of being applied by regulatory authorities, regulated gas businesses have consistently called for the implementation of genuine light-handed regulation. No Australian gas distribution network or pipeline company supports the current cost-based approach, as narrowly applied by State, Territory and Federal regulatory authorities. (Australian Gas Association, sub. 13, p. 40)

Box 8.2 Lighter handed gas regulation initiatives overseas

Most countries regulate the price of third party access to natural gas transmission pipelines and distribution networks. But there are some exceptions.

New Zealand

Light-handed pipeline regulation in New Zealand relies on general anticompetitive legislation, information disclosure requirements and an implicit threat of heavy-handed regulation at an industry level if market power is abused. This regime is currently undergoing a review by the New Zealand Commerce Commission in response to concerns about whether prices are too high and the credibility of the threat (Hodgson 2002, OECD 1999). The commission released a draft report in May 2004 (Commerce Commission 2004).

United States

All pipelines in the United States are subjected to cost-based price regulation. However, in recent years, the Federal Energy Regulatory Commission (FERC 2000) has been looking at ways of enhancing market efficiency, and in particular has signalled that its current regulatory framework might need modification to meet the needs of the changing gas market. The Federal Energy Regulatory Commission floated the idea of a two-track model of regulation in which 'non-captive customers would face market prices and service flexibility and captive customers would be able to obtain service at regulated rates' (FERC 2000, p. 43).

European Union

Under the 1998 European Union Directive, member countries were able to choose either a negotiated or regulated access regime (European Parliament 1998). Negotiated access regimes were defined under article 15 of the directive as being based on voluntary commercial agreements. Four European Union countries adopted negotiated third party access regimes: Germany, The Netherlands, Austria and Denmark. Some of these regimes suffered from a weak threat for service providers given there was no articulated provision for what would happen if market power was misused. In addition, there is a high degree of market concentration in several of these countries, which contributed to a less effective light-handed regime (IEA 2002a, 2002b, 2002c; and Lieb-Doczy and von Hammerstein 2003). A new European Union Directive in 2003 (European Parliament 2003) repealed the 1998 Directive and required all member countries to have regulated third party access. The main reason for this policy change was to promote consistent regulation between member states.

> A firm that has been through at least one 'building block' cost of service reviews should have close to efficient costs and could move to a lighter handed non-cost based method of regulation … (Alinta/Multinet, sub. 36, p. 19)

> … APIA strongly believes that the characteristics of the gas transmission sector make it a strong candidate for a substantial 'rolling back' of the current regulatory regime to a more light-handed framework. (APIA, sub. 44, p. 2)

> … Allgas Energy and ENERGEX consider that implementing new forms of regulation which can move the industry towards very light-handed or uncovered arrangements is an urgent task. (Allgas Energy, sub. 25, p. 5)

Some other interested parties also supported a light-handed form of regulation, including the Western Australian Government:

> … a light-handed regulatory approach may, in appropriate instances, provide satisfactory outcomes to service providers and customers at little cost, and a basis for successful negotiations. (sub. 70, p. 2)

In contrast, gas users tended to be apprehensive about a shift to light-handed regulation.

> … any predilection for 'lighter handed' regulation must be factually established and not be part of monopoly network service providers' latest regulatory gaming gambit. (Hunter Gas Users Group, sub. 4, p. 9)

> Before any moves to light-handed regulation could be contemplated, the end user would need to be made confident that the terms and conditions (including tariffs) at the commencement date of light-handed regulation are fair, reasonable, transparent and market competitive. Orica believes that the first round of access reviews in [New South Wales] has only removed a proportion of monopoly rents, with potential for more rents to be reduced. Any move to light-handed regulation will seriously compromise users' interests and crucially adversely affect their economic viability. Any move to light-handed regulation will be strongly contested and evidence required to be made public for examination. (Orica, sub. 28, p. 10)

Nevertheless, the analysis presented in earlier chapters demonstrates that the costs of the current regulatory approach (access arrangements with reference tariffs) will continue to be large. Hence, that approach should only be applied to pipelines where there are even larger benefits to outweigh the costs. For other covered pipelines, a less costly (light-handed) approach is required.

8.2 Proposed approach

The analysis in earlier chapters indicates that the costs of the current Gas Access Regime are linked to the prescription of reference tariffs. Hence, a light-handed form of regulation would need to avoid this aspect of the current regime and instead place greater emphasis on market-based outcomes. As noted in chapter 3, commercial negotiations are rare under the current regulatory approach of prescribing reference tariffs. Rather than facilitating market-based outcomes, reference tariffs have become the price at which most, if not all, third party access to a covered pipeline occurs.

Light-handed regulation without reference tariffs does not mean no regulation. Rather, the techniques discussed above can be used to influence commercial negotiations to promote competition in upstream and downstream markets. The Commission recognises that the likelihood of commercial negotiations resulting in the most efficient outcomes possible, depends on the market circumstances in which negotiations occur. Hence, the recommended test on the form of regulation in chapter 6 requires the Minister and the NCC to assess which form of regulation (an access arrangement with reference tariffs or a light-handed option) generates the greatest net benefits to the economy.

This framework for determining the form of regulation within the Gas Access Regime allows the decision maker to take into account a wide range of factors in deciding whether light-handed regulation is appropriate. This approach is similar to the decision framework outlined by NERA (2004) in a commissioned study for the ESC:

> The NERA report … discusses how the appropriate light-handed technique depends on a complex mix of market, institutional and procedural characteristics. These characteristics include the degree of actual and potential market competition, the extent of buyers' countervailing monopoly power, the stage of market development, the nature of the regulatory 'threat' and the size of the regulated entity. … Applying these criteria to the range of light-handed regulatory approaches can yield valuable insights about what light-handed regulatory technique may prove most appropriate in a given set of market and institutional circumstances. (ESC, sub. DR112, p. 20)

Drawing on the discussion of the various possibilities for a light-handed regime and the case studies above, the Commission considers that a light-handed approach, essentially based on monitoring, could be designed so commercial negotiations take place in a market where there is:

- separation of pipeline operations from associated businesses in upstream and downstream markets
- a commitment by service providers that they will enable third parties to access spare capacity
- a high level of transparency in the behaviour of service providers
- a credible threat that the misuse of market power would lead to the imposition of regulation that more directly controls the terms of commercial transactions.

The intention of a light-handed approach is to harness the potential of commercial negotiations to deliver more efficient outcomes, while giving assurance to those concerned about the misuse of market power. It could also become a transitional measure towards a deregulated market for pipeline services in the longer term.

RECOMMENDATION 8.1

The Gas Access Regime should be amended to provide for a light-handed form of regulation as an alternative to regulation involving an access arrangement with reference tariffs. The light-handed alternative should be a monitoring regime. It is important that the monitoring regime not develop into an intrusive and costly form of regulation.

Chapter 4 notes that a key objective of the Gas Access Regime is the promotion of competition in upstream and downstream markets through the provision of access to pipelines. Thus, the Commission considers that a key element of the light-handed option should be an access policy. Pipeline operators, at their discretion, would set out in their access policy the procedures and any terms and conditions for gaining access, the way they propose to handle matters relating to queuing, capacity trading and expansion, and provisions for binding commercial dispute resolution. In addition, to assist in providing incentives for service providers to negotiate in good faith, the anticompetitive conduct provisions of the Gas Pipelines Access Law (GPAL) could apply to service providers operating monitored pipelines (further details in section 8.3).

The ring fencing and associate contract requirements of the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) could be maintained for light-handed regulation to ensure the separation of pipeline operations from related businesses in other markets. However, the current ring fencing and associate contract provisions were designed as part of the current regulatory approach (access arrangements with reference tariffs). As a result, those provisions need some modification, the nature of which is discussed below (section 8.4).

As part of the monitoring regime, the behaviour of service providers could be made more transparent by requiring them to report information about their operations. This information reporting requirement would differ from that in the current Gas Code, since the data collected under the Gas Code are primarily intended for the derivation of reference tariffs at an access arrangement review. The Commission envisages that the data reporting arrangements under light-handed regulation would be far less intrusive than current requirements (further details are provided in section 8.5).

The Commission also envisages that there could be scope for service providers to adopt, at their discretion, other pro-competitive features. However, the Commission is not seeking to prescribe any of these techniques. Rather, service providers might find that one or more of the techniques prove useful in demonstrating to the regulator that they have negotiated in good faith and that they are committed to the policy objectives of the Gas Access Regime (further detail in section 8.6).

As noted, the Commission recommended maintaining the current regulatory approach (access arrangements with reference tariffs) for cases where the Minister judges its application to be warranted. Such cases could include those where the misuse of market power becomes evident after a period of light-handed regulation. That is, the abovementioned credible threat against the misuse of market power could be the prospect of being required to have an access arrangement with reference tariffs.

In summary, the Commission proposes that the monitoring regime would have the following features:

- a third party access policy offered by the service provider
- provision for action against the service provider or others where access is prevented or hindered (s.13 of schedule 1 of the GPAL)
- ring fencing and associate contract arrangements that ensure the separation of pipeline operations from associated businesses in upstream and downstream markets
- public disclosure of information by the service provider (which would be well short of the 'access arrangement information' currently required under the Gas Code)
- scope for the service provider to adopt, at its discretion, additional pro-competitive features, such as a code of conduct
- a credible threat that the misuse of market power by the service provider would trigger use of the Gas Code's heavy-handed regulation (an access arrangement with reference tariffs).

Under the monitoring regime, State and Territory regulators and the ACCC would continue to have a role. The Economic Regulation Authority (which has assumed the responsibilities of the former Office of Gas Access Regulation, OffGAR) emphasised the importance of the Commission clearly specifying this role:

> A specification of the task is what regulators actually need. If the task is to be done light-handed then a specification should say so and, in particular, I draw attention to an objects clause which says promotion of economic efficiency — in shorthand — and if you just give a regulator that objects clause and then tell him to go run a price monitoring scheme, you can bet he's going to do it with a determined approach to make sure that that's the outcome. To get that outcome he needs to be determined about it and intrusive and all sorts of things and the regulator will simply do it, because that is his legal obligation. To cut this short, you need to tell him what it is and how it is and say, 'this is to be done only in this way.' That will give not only the regulator clarification as to what legally it is required to do, but it will give great confidence to the people to whom the [Gas] Code applies. (trans., p. 992)

The Commission envisages that the regulator would play a role in the collection and publication of specified information. They would continue to have the power to enforce the civil penalty provision under s.13 of schedule 1 of the GPAL. The regulator would also play a role in applying, under certain circumstances, to have a pipeline moved from monitoring to heavy-handed regulation.

With regards to the objects clause, the Commission emphasises that the objects clause should not be used by the regulator to go beyond the functions specified in this chapter (recommendation 5.2 does not require the regulator undertaking the monitoring function to have regard to the objects clause). This is not to say that the objects clause is not relevant to the monitoring regime. On the contrary, the monitoring option forms part of the overall package of the Gas Access Regime, which is intended to achieve the objective specified in the objects clause.

Participants' views

In response to the Commission's draft report for this inquiry, there was broad support for a light-handed option:

> AGL [Australian Gas Light Company] welcomes the acknowledgement that there can be substantial costs under the existing regime. We support the introduction of a truly light-handed price monitoring regime … [and] we believe it is important that the price monitoring tier remains truly light-handed, [and] that it not be hampered by complex information disclosure and other administrative requirements … (AGL, sub. DR84, p. 3)

> The ENA [Energy Networks Association] is supportive of the Productivity Commission's recommendations for lighter handed regulation and considers their effective implementation has the potential to substantially reduce the risks and costs of regulation under the current regime for some networks and pipelines. (Energy Networks Association, sub. DR85, p. 23)

> Envestra supports the Commission's recommendation for a monitoring regime as a lighter handed means of regulation. (Envestra, sub. DR82, p. 5)

> The companies strongly support the Commission's recommendation that price monitoring of [gas] utilities should be introduced into the national Gas Code. (Alinta/Multinet, sub. DR91, p. 2)

> Goldfields Gas Transmission agrees with the Commission's rationale and proposal … in regard to the proposed lighter handed regulatory option. (Goldfields Gas Transmission, sub. DR88, p. 46)

> Shell supports [the] move [to a monitoring regime, with application of an access arrangement with reference tariffs only in more extreme circumstances] as a positive step towards moving from a fully integrated market towards a fully free market. (Shell, sub. DR95, p. 4)

The ESC believes that a price monitoring approach may prove to be effective if it is well specified, accompanied by a clear regulatory threat and applied in the appropriate circumstances. (ESC, sub. DR112, p. 22)

The proposed features of the monitoring regime provide a solid basis for development. The provision of a third party access arrangement [policy] developed by the service provider, and scope to adopt other pro-competitive features, should serve to enhance commercial negotiations under a monitoring regime. Less onerous and intrusive information requirements that maintain accountability and transparency of service provider operations are also desirable features. (Western Australian Government, sub. DR114, p. 11)

The Australian Council for Infrastructure Development articulated some of the benefits of price monitoring 'as a lighter handed alternative to price caps or cost-based regulation':

The key advantages of price monitoring over heavy-handed price controls include:

- its ability to significantly reduce regulatory risk and to offer the investor high certainty and a greater preinvestment understanding of the regulatory environment
- because of the relatively low levels of regulatory intervention in price setting there is less opportunity for regulatory error and consequent distortions
- it best meets the requirements of a 'workable' competitive market where customer welfare is maximised through encouraging price service offerings that best meet customer needs
- it is less information intensive and therefore relatively inexpensive to administer
- it best encourages commercial negotiations. (sub. 1, p. 4)

On the other hand, several participants expressed concern about the Commission's proposal for light-handed regulation:

… in the case of the gas industry where elements of the industry continue to possess substantial market power, price monitoring would not be an effective substitute for the current regime. This is the case because price monitoring does not provide a mechanism for adjusting behaviour and facilitating access on reasonable terms and conditions. In addition, price monitoring does not provide a mechanism for reducing prices in an environment where costs are declining. If price monitoring is combined with a threat of future regulatory intervention then such an approach increases the level of regulatory risk … Price monitoring is a reasonably resource intensive process and may require the same level of resources as the current regime. This is especially the case where a judgment needs to be formed on the reasonableness of the prices imposed. (ACCC, sub. 48, p. 32)

The 'monitoring regime' offers users no protection whatsoever and will not bring about economic efficiency. … WPC [Western Power Corporation] rejects the argument that the monitoring regime provides an environment conducive to negotiation between users and service providers. Proponents of the monitoring regime fail to take into account

> users' lack of negotiating power and lack of information when negotiating access contracts. (Western Power, sub. DR115, pp. 27 and 30)
>
> In practice, it is highly likely that the proposed monitoring regime would not be capable of discerning the abuse of monopoly power unless a full analysis of pipeline costs is undertaken, as is the case currently. (BHP Billiton, sub. DR96, p. 3)

The Commission acknowledges the concerns of participants and has sought to address these concerns in later sections of this chapter, which detail aspects of the proposed monitoring approach. In addition, the Commission's two-tiered approach would only lead to light-handed regulation of pipelines where the net benefits of that approach are greater than the net benefits of an access arrangement with reference tariffs (chapter 6).

The Commission considers that the package should enable the costs of price regulation to be avoided, while providing users with a degree of confidence that the behaviour of service providers is being monitored and still facilitating third party access. In other words, it enables the benefits of the existing regime to be achieved, but at a lower cost to the economy.

RECOMMENDATION 8.2

The proposed monitoring form of regulation to be incorporated into the Gas Access Regime should have the following features:

- ***a third party access policy formulated by the service provider which would have some minimum requirements relating to processes for negotiating access and binding arbitration in the event of a dispute over access***
- ***subjecting service providers to provisions for anticompetitive conduct (the current s.13 of schedule 1 of the Gas Pipelines Access Law)***
- ***minimum ring fencing provisions***
- ***public disclosure of specified information by the service provider for monitoring purposes only (which would be well short of the 'access arrangement information' currently required under the Gas Code)***
- ***scope for the service provider to adopt, at its discretion, additional features, such as a voluntary code of conduct.***

Several participants sought greater information on the components of the monitoring regime and urged the Commission to provide greater clarity in the final report:

> … the details of the regime and how it would operate are still at the early conceptual stage, which makes it difficult to draw definitive conclusions. (Western Australian Government, sub. DR114, p. 11)

> … ENA [Energy Networks Association] recommends the Commission address [the development of information disclosure guidelines for the price monitoring option] … in further detail in its final report. (Energy Networks Association, sub. DR85, p. 24)
>
> APIA considers that while … [the draft] recommendations [on monitoring] go some way towards minimising the risk associated with introducing a new level of regulation there remain a number of critical issues to be resolved. (APIA, sub. DR100, p. 31)
>
> A … problem with the monitoring option is that it is not at present well specified. (ESC, sub. DR112, p. 21)

The following sections of this chapter aim to bring greater clarity to components of the monitoring regime.

8.3 Access policy

A key aspect of the Commission's proposed monitoring regime is a third party access policy. As noted above, the Commission does not think the elements of an access policy should be prescribed by the Gas Access Regime, but rather service providers should have discretion to develop their own access policy and to specify the details of each element.

Several sections of the existing Gas Code provide guidance on the elements that could form the basis of the access policy. For example, s.3 of the Gas Code sets out the minimum contents of an access arrangement, including:

- a services policy (ss3.1–3.2)
- a reference tariff and a reference tariff policy (ss3.3–3.5)
- the terms and conditions of supply (s.3.6)
- a capacity management policy (ss3.7–3.8)
- a trading policy (ss3.9–3.11)
- a queuing policy (ss3.12–3.15)
- an extensions/expansions policy (ss3.16).

Section 5 of the Gas Code requires service providers to maintain an information package for prospective users on request and outlines procedures to be followed when a user requests access. Further, service providers are required to establish and maintain a public register of capacity. Section 6 of the Gas Code details procedures for dispute resolution over access terms and conditions.

In New Zealand, a voluntary third party access policy (the Gas Pipeline Access Code) operates as a complement to the price monitoring regime. The policy was negotiated between 1995 and 1998 by a set of committees including all major industry participants. The major provisions include:

- rules on the use of spare capacity
- rules for the timeliness of response to capacity development requests and allocation of capacity where it is limited
- general pricing principles (including encouraging economic efficiency) and making publicly available the terms of a negotiated price service
- constraints on the release of confidential information to affiliates
- receipt and delivery points
- queuing for uncommitted capacity
- expansion of capacity (Ministry of Economic Development 2002).

Participants' views

Several service providers made useful suggestions about the information content of an access policy. Duke Energy International (sub. 21, pp. 26–7) suggested some minimum information that a service provider subject to light-handed regulation could be required to convey to all access seekers:

- the nature of the service
- procedures for prospective users that wish to gain access to a pipeline
- the gas path (receipt and delivery points — basis for variation)
- charges (both for the basic service and any additional components such as odourising, treatment of user specific facility charges)
- nominations and nomination procedures
- trading or assignment of capacity
- gas quality specifications and
- capacity information.

APIA (sub. DR100, p. 35) submitted that the provisions of the access policy could be those contained in the voluntary code of conduct it proposed in an earlier submission (sub. 44, pp. 69–70). This includes:

- spare capacity trading
- facilitating commercial dealings between the parties
- principles to assist in dispute resolution.

Enertrade endorsed the components of the access policy put forward by APIA including:

> Publication by the pipeline owner of a document that sets out principles of nondiscrimination, access, service offerings, prices, dispute resolution processes, capacity trading mechanisms, expansions and extensions policy and terms and conditions of standard contracts … A process that ensures that all the relevant details of contracts with associated entities are made public and an undertaking that all those terms and conditions must be made available to any other bona fide pipeline user that requires a materially equivalent service … An annual process whereby an external auditor determines whether the pipeline owner has complied with both the spirit and content of the access principles. The results of the audit would be published at the same time as an annual financial report … Dispute resolution, ultimately through an independent arbitrator (that is, not a regulator under the [Gas] Code). (sub. DR98, pp. 7–8)

Epic Energy (sub. DR109, p. 29) endorsed the code of conduct put forward by APIA and elaborated on access principles that should be disclosed: tariff and service policy, queuing policy, extensions/expansions policy, minimum terms and conditions, capacity management policy, system capacity and investigations to expand or extend the pipeline.

Recognising that timing is a key element of an access policy, Duke Energy International commented:

> Service providers would be required to provide the minimum information requirements to users within reasonable timeframes, in order to prevent deliberate stalling and ensure the negotiation process is as efficient as possible. The timeframe may vary for different customers, particularly where the service provider needs to undertake technical analysis (for example, modelling) based on a user's request. (sub. 21, p. 26)

Allgas Energy (sub. 25, p. 25 and attachments 2 and 3) preferred a price–service offering (PSO) model (discussed in further detail in section 8.6). It provided considerable detail about alternative ways in which to implement a PSO regime. The terms of the PSOs could be set by negotiation with consumer groups, with negotiations facilitated by information disclosure on the service provider's part. It recommended the outcomes of negotiations be subject to regulatory oversight.

Western Power did not endorse the implementation of the monitoring option, but nevertheless commended that an access policy formulated by the service provider:

> … must require the service provider to specify in the third party access policy at least one service (and preferably a number of services), the terms and conditions on which the service will be provided and the tariff applicable to the service. The service provider would be required to make that service available to a prospective user seeking the service, subject to there being spare capacity available. (sub. DR115, p. 38)

Similarly, Project Consultancy Services considered service providers should publish a suite of access tariffs that may be differentiated principally by the duration of the third party contract. The published tariffs would:

> … focus on a reference service of short duration for relatively small or variable volumes … [such that] … third parties who are prepared to contract for large volumes of pipeline services for a long period and, or, are prepared to make concessions on contract flexibility, or to improve cash flow security, would be able to negotiate the value of these contract concessions. (sub. DR102, p. 11)

Several service providers considered dispute resolution should be an element of the service provider prescribed access policy. Epic Energy (sub. DR109, p. 28) considered there should be an arbitration body (similar to the Australian Competition Tribunal). There would be a minimum of three arbitrators for each dispute, drawn from a panel of potential members with a variety of backgrounds and expertise. It considered the arbitrators should take into account the factors in clause 6(4)(i) of the Competition Principles Agreement.

Users also considered dispute resolution an important element:

> WPC [Western Power Corporation] would be very concerned with the monitoring option if there is no ability to seek binding dispute resolution, because, as stated, users simply cannot afford to wait five years, or longer, for the opportunity to commence an access dispute in relation to a pipeline where the service provider is exercising monopoly power. Users will be forced, because of commercial constraints, to enter into contracts under which they pay monopoly rents, because their only alternative in the medium term will be 'no deal'. (Western Power, sub. DR115, p. 38)
>
> Worsley is concerned that the monitoring option does not provide for binding dispute resolution. A user who has been unable to achieve a satisfactory outcome in negotiations with a service provider has no avenue through which they can pursue access in the face of refusal to grant access by the service provider. (Worsley Alumina, sub. DR110, p. 14)

The NCC considered:

> … it is essential for any price monitoring regime operating under the Gas Code to include a mechanism for resolving access disputes. The [National Competition] Council favours modifying the obligations proposed for the price monitoring regime to include an arbitration process through use of an independent binding dispute resolution mechanism. It also considers that it is a necessary requirement for a workable model that arbitration be funded by the disputing parties so as to provide an incentive to achieve commercially negotiated outcomes. Where access seekers and service providers cannot agree on an appropriate way to resolve their dispute within a reasonable period of time, the regulator should invoke the default dispute resolution option under the Code. (sub. DR92, p. 13)

The NCC further noted that the exclusion of dispute resolution provisions in the monitoring regime would have implications for certification of the Gas Access Regime (discussed in section 8.9).

The Commission's assessment

Most of the provisions suggested by Duke Energy International, APIA, Enertrade and Epic Energy mirror the requirements of an access arrangement under s.3 of the Gas Code and seem to be important, if not essential, ingredients of an access policy. In addition, the provisions in s.5 of the existing Gas Code that set out procedures for negotiating access and the requirement for a capacity register, are elements that would ordinarily form part of an access policy. This should give an access seeker guidance on the timeliness of responses to capacity development requests and allocation of capacity where it is limited.

The Commission considers that a service provider prescribed access policy should contain most of these elements, although the service provider should have discretion to decide on the details of the included elements and to choose not to include some elements. (The Commission notes it would ordinarily be prudent for a service provider to justify the exclusion of certain core elements.) Inclusion of prices and charges should not be viewed as an essential element, provided there are other features in place to facilitate access negotiations. However, it should be open to a service provider to adopt a PSO model, under which it voluntarily reveals charges for its standard packages.

Whilst these requirements will not be prescribed in the monitoring regime, there is an expectation that service providers will take formulation of an access policy seriously. The access policy, together with other information, could form part of the decision on the form of regulation at the time of review, where this transpires (discussed in section 8.7).

Regarding dispute resolution, the Commission is of the view that it should be mandatory for a service provider to specify a commercial dispute resolution process. The access policy should stipulate that the outcome of the process will be binding. Arbitrators should be privately appointed (therefore removing the relevant regulator from a potential role arbitrating disputes over access to monitored pipelines). The Commission considers the costs of arbitration should be borne by both service providers and access seekers to provide an incentive for both parties to reach a negotiated outcome.

The Commission considers the dispute resolution policy should specify who the arbitrator will be. There are a number of independent mediation schemes throughout

Australia such as the Institute of Arbitrators and Mediators, the Australian Commercial Disputes Centre, and Lawyers Engaged in Alternative Dispute Resolution. Some of these organisations have arbitrators from a variety of backgrounds including engineering, economics, accounting and law (IAMA 2004). Service providers could also draw on the formal arbitration models set out in commercial arbitration acts, which all State and Territory governments have enacted.

Taken together with the penalties for preventing and hindering access (below), the Commission considers a binding dispute resolution process should allay the concerns of some users about a lack of options if negotiations between the service provider and access seeker break down.

The provisions of s.6 of the existing Gas Code (relating to arbitration) would not apply to monitored pipelines.

RECOMMENDATION 8.3

The access policy prescribed by service providers under the proposed monitoring regime should include at a minimum:

- ***processes for negotiating access***
- ***dispute resolution procedures (including provision for binding commercial arbitration).***

FINDING 8.1

A service provider in formulating its access policy would be guided by the requirements of parts of s.3 of the Gas Code, which includes:

- *a services policy (ss3.1–3.2)*
- *a reference tariff and a reference tariff policy (ss3.3 and 3.5)*
- *the terms and conditions of supply (s.3.6)*
- *a capacity management policy (s.3.7)*
- *a trading policy (ss3.9–3.11)*
- *a queuing policy (ss3.12–3.13 and 3.15)*
- *an extensions/expansions policy (ss3.16).*

Subjecting service providers to provisions for anticompetitive conduct

As noted earlier, a key objective of the monitoring regime is to place greater emphasis on encouraging commercial negotiations between service providers and access seekers. The access policy would form the basis of such negotiations. To assist in providing incentives for service providers to negotiate in good faith, the Commission considers the anticompetitive conduct provisions of the GPAL could apply to service providers operating monitored pipelines.

The existing provision in the Gas Access Regime is s.13 of schedule 1 of the GPAL (hereafter referred to as s.13 in this section), which provides recourse through the courts for access seekers that are not able to gain access to a covered pipeline. Section 13 is essentially the same as s.44ZZ of the national access regime and similar to part IV (s.46) of the Trade Practices Act. It provides a purpose test that prohibits a business from engaging in conduct for the purpose of preventing or hindering access. Examples of conduct (listed in the footnote to the heading of s.13) are refusal to supply, limiting or disrupting supply, and refusal to sell on reasonable terms and conditions.

Section 13 operates as both a civil penalty and a conduct provision:

> [Section 13] prohibits a service provider, user or an associate of a service provider or user from engaging in conduct for the purpose of preventing or hindering access to a service provided by means of a [Gas] Code pipeline. See Part 5 [of the GPAL] for proceedings that may be taken in the event of a breach of the clause (which is a civil penalty provision and a conduct provision). (House of Representatives, South Australia 1997)

The penalties for a breach of s.13 are set out in part 5 of schedule 1 of the GPAL. Because s.13 is defined as a civil penalty provision, the relevant regulator may apply to a court in respect of a breach of this section (s.34[1]) — the penalty, if imposed, being payable to the Minister (s.34[3]). The maximum civil penalty for a breach of s.13 is $100 000 (in all States and Territories) (Gas Pipelines Access (South Australia) Regulations 1999). Western Australia, has an additional daily penalty of $20 000 where the breach continues after the regulator has given notice that it will apply the daily amount (Gas Pipelines Access (Western Australia) Regulations 2000). In addition, s.13 is a conduct provision, which means the regulator or any other person can apply for an injunction, a declaration (that a contravention has occurred and should be ceased or remedied), and damages to recover any loss arising from the contravention.

The Commission considers that s.13 should be available to all access seekers where service providers or others (listed in the provision) with the ability to prevent or hinder access (such as contracted customers), are engaging in the prohibited conduct.

RECOMMENDATION 8.4

Under the proposed monitoring regime, to encourage service providers to provide third party access, service providers and related parties should be subject to the anticompetitive conduct provisions of the Gas Pipelines Access Law dealing with preventing or hindering access (s.13 of schedule 1 of the Gas Pipelines Access Law).

8.4 Ring fencing provisions

In the draft report for this inquiry, the Commission considered that monitored pipelines should be run at arms length from associated businesses in upstream and downstream markets. Following the draft report, several participants proposed maintaining ring fencing provisions for pipelines covered under the monitoring regime (AGL, sub. DR84, p. 25; Epic Energy sub. DR109, p. 29; Alinta/Multinet, sub. DR91, p. 7; Envestra, sub. DR82, p. 10; and ExxonMobil, sub. DR78, p. 6). The Western Australian Government noted that it:

> … believes transparency between the service provider and operations in dependent markets is critical to promote competition … (sub. DR114, p. 11)

The issue is whether this can be achieved using the current requirements of the Gas Code (with or without amendment) or whether alternative ring fencing and associate contract provisions should be devised.

The current ring fencing provisions in the Gas Code (ss4.1–4.24) require, *inter alia*, each service provider to be a separate legal entity not carrying on a related business, and maintenance of accounts that allocate costs shared between covered and uncovered services in accordance with the reference tariff principles specified in s.8.1 of the Gas Code:

> A person who is a Service Provider in respect of a Covered Pipeline … must comply with the following: …
>
> (c) establish and maintain a separate set of accounts in respect of the Services provided by each Covered Pipeline … ; …
>
> (e) allocate any costs that are shared between an activity that is covered by a set of accounts described in section 4.1(c) and any other activity according to a methodology for allocating costs that is consistent with the principles in section 8.1 [reference tariff general principles] and is otherwise fair and reasonable; … (Gas Code, s.4.1)

The provisions ensure the separation of vertically integrated businesses and also establish measures for horizontal separation, that is, separation of accounts where a service provider owns multiple pipelines.

Section 4.2 of the Gas Code gives regulators the power to seek financial information (on the allocation of costs between services) to verify the calculation of reference tariffs. Section 4.2 also requires compliance with accounting guidelines published or approved by the relevant regulator. Under s.4.12 of the Gas Code, the regulator can require a service provider to demonstrate the adequacy of their internal procedures to comply with ring fencing provisions upon reasonable notice. Under s.4.13 of the Gas Code, service providers must report to the regulator at reasonable intervals describing the measures taken to ensure compliance with obligations under s.4.

Several service providers commented more specifically on ring fencing provisions for monitored pipelines:

> The fundamental elements of the ring fencing provisions of the [Gas] Code could be implemented simply by adopting the current section 4 of the Code but with the following sections omitted — 4.1(c), (d) and (e), 4.2–4.11, 4.13. (Envestra, sub. DR82, p. 10)
>
> APIA proposes that … [monitored] pipelines continue to be covered by the existing ring fencing provisions of the Gas Code with the exception of requirements 4.1(c) and 4.1(e) dealing with the requirement to maintain separate accounts and to allocate shared costs. (APIA, sub. DR100, p. 56)

Epic Energy (sub. DR109, p. 29) noted that ring fencing requirements similar to those in s.4 of the Gas Code would be appropriate, provided the confidentiality of information was not compromised.

Alinta/Multinet commented:

> The companies consider that … [*inter alia*] ring fencing proposals formulated by the service provider in a public code of conduct should be sufficient for a vertically integrated supplier to be able to be price monitored. A public disclosure of ring fencing proposals is a powerful incentive for a service provider to stick to the terms of the commitment. For a non-vertically integrated supplier there should only be the requirement for a public commitment to open access. The companies consider that this voluntary commitment to ring fencing … is a less costly and more powerful incentive to ensure appropriate behaviour. (sub. DR91, p. 7)

The Economic Regulation Authority noted that if the current ring fencing provisions of the Gas Code apply, this will require a high level of information disclosure to enable the regulator to verify compliance with ring fencing provisions:

> … it will place similar obligations on regulators and information requirements for service providers as exist now for regulators to agree and effectively oversight continued compliance with that obligation for separation of businesses. (sub. DR116, p. 9)

The Commission's assessment

The Commission considers that it is necessary to maintain ring fencing under the monitoring regime. The credibility of the monitoring regime, and the achievement of the Gas Access Regime's objective, is enhanced by requiring the activities of monitored pipelines to be kept separate from related businesses in other markets.

The minimum requirements set out in s.4.1 of the Gas Code are consistent with the light-handed monitoring approach. That is, they focus on self regulation, and the provisions are not overly intrusive. It is likely that a service provider of a monitored pipeline will be complying with many of the requirements already.

However, the current ring fencing provisions were designed as part of a package for cost-based price regulation. Section 4 of the Gas Code, therefore, gives the regulator strong powers to seek information and to use the information to verify that reference tariffs comply with the Gas Code's pricing principles. Thus, s.4 should be amended to remove the obligations on the regulator to oversight compliance with ring fencing provisions. Elements of s.4, other than s.4.1, should therefore not apply to monitored pipelines (including the additions to s.4.1 recommended in chapter 10).

However, s.4.1(e) requires amendment to ensure that the method for allocating costs under s.4.1(c) is transparent and disclosed, but need not comply with the Gas Code's pricing principles. This is not necessary as the regulator does not need to verify the method for the purpose of determining reference tariffs. Thus s.4.1(e) should be replaced with an alternative formulation.

The Commission envisages that the information maintained by a service provider of a monitored pipeline under s.4.1 of the Gas Code will form the basis of some of the information disclosure requirements of the monitoring regime (section 8.5 below).

RECOMMENDATION 8.5

Under the proposed monitoring regime, a service provider should comply with the minimum ring fencing requirements in s.4.1 of the Gas Code. However, s.4.1(e) should not apply for monitored pipelines, rather a new alternative provision should apply as follows:

> ***allocate any costs that are shared between an activity that is covered by a set of accounts described in s.4.1(c) and any other activity according to a methodology for allocating costs that is transparent and disclosed as part of the monitoring regime information disclosure requirements.***

8.5 Information disclosure

As noted, a key aspect of the Commission's proposed monitoring form of regulation is to make the service provider's behaviour transparent, through reporting requirements. Such reporting requirements would be well short of the 'access arrangement information' currently required under the Gas Code, since the data collected under the Gas Code are primarily intended for deriving cost-based reference tariffs. The Commission envisages the data reported under the monitoring regime would be far less intrusive.

The data disclosed by a service provider have to make its behaviour sufficiently transparent so that, if there is a misuse of market power, it would be apparent. This does not necessarily require the reporting of huge amounts of information. Indeed, there is a risk that 'information overload' would mask a service provider's behaviour. That is, transparency could be undermined if people have to employ data analysts to understand the performance of a service provider and get preoccupied with assumptions for cost allocation and so forth. On the other hand, the data should not be so sparse that they provide few insights into a service provider's performance.

It is also important to be mindful of the costs to service providers of preparing the required data. As noted in chapter 7, the current information requirements of the Gas Code are costly and intrusive. These requirements can be justified only if a regulator is to approve reference tariffs.

> The information gathering provisions of the Gas Access Regime are expansive and their application by regulatory authorities have in many circumstances resulted in unnecessary costs to regulated gas businesses. Information gathering costs are particularly high under the heavy-handed forms of cost-based access pricing applied by existing regulators. (Australian Gas Association, sub. 13, p. 95)

To limit compliance costs under the monitoring regime to reasonable levels, the data reporting requirement should:

- specify only the minimum data necessary to provide insight on service providers behaviour and commercial negotiations with potential access seekers
- to the maximum extent possible, rely on record keeping and accounting practices that already exist as part of standard business practices.

New Zealand pipelines and Australian airports

The information disclosure requirements under the monitoring regimes for gas pipelines in New Zealand and airports in Australia can provide some insights and guidance on possible reporting requirements.

New Zealand gas pipelines information disclosure

In New Zealand, gas transmission and distribution activities are subject to price and quality monitoring under the Gas *(Information Disclosure) Regulations 1997* (NZ). The information that pipeline operators are required to disclose is detailed in box 8.3.

Box 8.3 Information disclosure requirements for New Zealand gas pipelines

Gas transmission and distribution activities are subject to price and quality monitoring under the Gas (Information Disclosure) Regulations 1997. The regulations, administered by the Ministry of Economic Development, require those involved in gas transmission and distribution to disclose:

- audited financial statements for distribution and transmission activities (based on guidelines for the allocation of costs and revenues published by the Ministry of Economic Development)
- financial performance measures — accounting return on total assets, accounting return on equity, accounting rate of profit
- certain details about contracts for conveyance of gas through pipelines
- efficiency performance measures — direct line costs per kilometre, indirect costs per gas consumer
- energy delivery efficiency performance measures — load factor, unaccounted for gas ratio
- statistics — system length, maximum monthly gas entering the system, total amount of gas conveyed, total amount of gas conveyed on behalf of others, total customers
- reliability performance measures — planned and unplanned interruptions, incidents of damage requiring repairs to distribution networks, the number of gas leaks detected by routine survey, the number of publicly reported escapes of gas on the entire distribution network
- pipeline capacity — must be disclosed publicly at the beginning of each financial year, including pipe diameters, compressor stations, pressure reduction stations, isolation valves and intake and offtake points.

Source: Gas (Information Disclosure) Regulations 1997.

Overall, the New Zealand requirements do not appear to be particularly onerous. The financial information required to be disclosed in the New Zealand regime is generally high level financial information, similar to that reported in annual reports. Disclosure of some contract details, including price, is arguably the most intrusive requirement, but this is still well short of the Australian Gas Code requirements because there is no assessment of the appropriateness of these prices. The requirement to allocate costs and revenues between the activities of a pipeline owner (such as transmission and distribution) is consistent with the current requirements to comply with the ring fencing obligations under s.4 of the Australian Gas Code. In New Zealand, the allocation of cost and revenues between activities must be based on a mandatory avoidable cost allocation methodology (Ministry of Economic Development 2002).

The financial and efficiency performance measures reported are simple calculations based on financial and other information, and could provide some insight into the performance of a service provider, particularly when considered over time.

Australian airports information disclosure

In Australia, airports subject to the monitoring regime are required to comply with the airports reporting guideline (ACCC 2004b) and the guidelines for quality of service monitoring at airports (ACCC 2003c). The information that airport operators are required to disclose under these guidelines is summarised in box 8.4.

Although some of the information reported under the airports monitoring regime is airport specific, the more generic information requirements may be suitable to be adopted under a system of price monitoring for gas pipeline services.

At the aggregate level, the financial information reported is reasonably high level and consistent with standard business reporting requirements. The requirement to allocate revenues, costs and asset values between aeronautical and non-aeronautical services, reflects the fact that some of the bundle of services supplied by airports are subject to regulation and others are not.

The more disaggregated cost and revenue information is provided at an individual service level for aeronautical and aeronautical-related services. Such a breakdown can provide insight into the drivers of any changes in overall profitability, without the need to allocate fixed costs between the individual services.

Information to be disclosed for Australian gas pipelines

The Commission considers that the information disclosure requirements for gas pipelines should balance the need to provide sufficient information to ascertain the misuse of market power, while not reverting to the onerous requirements under cost-based price regulation.

Box 8.4 **Information disclosure requirements for Australian airports**

Information that airport operators are required to supply under the airports reporting guideline includes:

- profit and loss account, including an allocation of revenues, costs and profits between aeronautical and non-aeronautical services (including basis for allocation)
- balance sheet including an allocation of assets between aeronautical and non-aeronautical services
- cash flow statement
- schedule of changes in asset values for aeronautical and non-aeronautical services
- operational statistics including passenger numbers, aircraft movements, staff numbers, area of land (aeronautical and non-aeronautical)
- schedule of aeronautical and aeronautical-related charges — per unit charges at an individual service level
- aeronautical and aeronautical-related revenue and cost schedules — more detailed information about revenues and costs at an activity level
- estimation of the weighted average cost of capital — operators can use their own methods but must be explicit about formulas and assumptions. The estimates are not audited
- related party transactions — information about transactions or contracts between businesses within the reporting structure of the airline operator including the value and nature of the transaction and the basis of price used in the transaction.

Indicators of quality which airport operators are required to disclose can be grouped into three main areas:

- airside — comprising services or facilities associated with runways and taxiways
- terminal — comprising services or facilities provided within the terminal building
- ground access — comprising services or facilities related to ground access, including car parking and road side access.

The following types of indicators are used:

- measures of capacity utilisation
- direct measures of waiting times at major passenger processing stages
- customer perception surveys, regarding the standard of service and facilities made available in terminals and associated with ground access
- airline response to annual questionnaires
- information from airlines relating to the standard of facilities provided to them.

Sources: ACCC 2003c, 2004b.

Developing consistent information disclosure requirements might also ensure:

- service providers have limited opportunity to conceal any misuse of market power through ‘creative accounting’
- there is consistency between service providers in a single jurisdiction, and for a single service provider that operates across jurisdictions.

This section considers several different types of information disclosure that could form part of the monitoring package:

- access negotiations
- financial statements
- key input and output prices and quantities
- dealings with associates
- measures of service quality.

Access monitoring

One of the key areas relevant to monitoring access is information about the provision of third party access. Observing the extent to which negotiations are taking place, as well as instances where negotiations have succeeded and failed can provide insight into whether the service provider is exercising market power in these negotiations.

Several participants responded to the Commission’s draft report proposal to particularly monitor cases in which negotiations have failed. Goldfields Gas Transmission (sub. DR88, p. 46) urged the Commission to focus on monitoring access. Similarly, APIA noted that the focus of the monitoring regime should be on the interaction between the provision of access to gas transmission pipelines and competition in upstream and downstream markets. In this regard, it submitted:

> … the information that is most relevant to this inquiry relates to the access policy that is adopted by the service provider and the actual history of negotiations for access to the pipeline. (sub. DR100, p. 31)

APIA provided detailed comments on what access information should be disclosed:

- the number of negotiations commenced within the year
- the number of negotiations completed resulting in an access agreement being negotiated
- the number of access negotiations withdrawn from by the access seeker
- the number of negotiations in dispute

- the number of dispute resolution processes commenced
- the number of dispute resolution processes completed. (sub. DR100, p. 36)

The Commission considers that there should be monitoring of access negotiations and more specifically, considers the information suggested by APIA is a good guide. The Commission considers that in addition to this data suggested by APIA, the service provider should disclose the number of access negotiations withdrawn by the service provider (this will usually be zero, but should be reported nonetheless). Information on the number of dispute resolution processes completed should be accompanied by a set of notes explaining what happened to these disputes (that is, whether they resulted in access or not).

The Commission also considers there could be merit in requiring service providers to report the duration of commercial negotiations. This requirement could provide an incentive for service providers to be timely in their response to access seekers.

Financial statements

It is common for monitoring regimes to require disclosure of financial statements, which is fundamental to assessing overall financial performance. As noted by Enertrade:

> … [the financial statement provides] a means of monitoring, 'Is this company doing either too well or not well enough?' … In my view the financial statement [a] listed company provides is the best and first starting point for [transparency and accountability of behaviour]. (trans., pp. 549 and 551)

Service providers are required to be separate legal entities (with a separate set of consolidated accounts) under the ring fencing requirements of the Gas Code (s.4.1). Most service providers would also meet the criteria specified in the *Corporations Act 2001*, requiring them to keep and lodge these financial reports with the Australian Securities and Investment Commission (ASIC). The financial reports include:

- statement of financial position (formerly called balance sheet)
- statement of financial performance (formerly called profit and loss statement)
- statement of cash flows
- notes to financial statements
- Directors' declaration and report
- auditor's report (ASIC 2004).

The ASIC statements set a minimum reporting standard. Any information published by the service provider (such as company accounts in annual reports) would also be available to the regulator undertaking the monitoring function.

In addition to these financial statements, it may be desirable to require accounting statements to be more disaggregated for regulatory purposes. Under the airports monitoring regime, the audited financial statements of the airport operator form the basis for preparing regulatory accounting statements. However, the latter must be accompanied by a series of supporting schedules, for example, a disaggregated schedule of aeronautical and non-aeronautical assets, of expenses, and of aeronautical and aeronautical-related revenue (box 8.4).

APIA considered that the financial information provided under the airports monitoring regime is 'highly intrusive':

> The information requested from providers of aeronautical services is at least as detailed as applies to information currently required of gas transmission businesses under the Gas Access Regime. (sub. DR100, p. 31)

The Commission is not convinced that the airport information requirements are as intrusive as the current Gas Access Regime information requirements. The Commission considers the information collected for monitored airports would be appropriate for monitored gas pipelines. Asset and depreciation values would be as reported in the company accounts. Further, the information would be used for a vastly different purpose (monitoring as opposed to approving an access arrangement with reference tariffs).

Using consolidated company accounts as the basis for monitoring would ensure the regulatory accounting statements comply with Australian accounting standards. This would require the regulatory accounting statements to be accompanied by notes that explain transactions and financial position and performance, and should reduce the possibility for service providers to 'manipulate' the information being provided to the regulator undertaking monitoring. Service providers could also be required to draw attention to circumstances in which accounting policies have changed between reporting periods.

There is another reason why it is desirable to require the consolidated financial accounts prepared for ASIC to form the basis for regulatory accounts. Enertrade (trans., p. 550) noted that in the United States, regulated pipeline companies have a set of accounts for financial purposes (to comply with accounting standards) and a separate set to comply with regulatory standards. (The regulatory accounts are set out in Federal Energy Regulatory Commission form no. 2 and require extensive detail to be reported for each pipeline). The Productivity Commission considers this is a very costly route to pursue and therefore considers that the financial statements reported under the monitoring regime should be based on those prepared for ASIC. Separation of ASIC accounts and regulatory accounts would entail a shift in focus to understanding the assumptions and methods used to prepare the regulatory accounts.

The Commission considers that the requirement to report an estimate of the weighted average cost of capital is unnecessary for each individual gas pipeline. The imprecision and subjectivity associated with estimating the weighted average cost of capital for an individual asset is discussed in more detail in chapter 7.

Allocation of costs and revenue might be needed because some services might be subject to monitoring and others might not. Similarly, some gas pipeline companies in Australia own and operate several pipelines and would need to allocate costs and revenues between these services. However, the extent to which allocation is needed may be mitigated by the capital intensive nature of the industry:

> … for gas transmission pipelines, operating costs (which are the subject of cost allocation rules) are likely to be limited to between 10 per cent and 20 per cent of total costs reflecting the highly capital intensive nature of gas pipeline services. (APIA, sub. DR100, p. 56)

The ring fencing provisions of the Gas Code require service providers to establish and maintain a separate set of accounts for each covered pipeline. The Commission has recommended that service providers of monitored pipelines comply with these provisions (section 8.4 and recommendation 8.6).

The Commission acknowledges valid concerns about methods for the allocation of costs and revenue. In particular, debatable and arbitrary assumptions are often required to allocate common costs and revenues. However, the effectiveness of the regime depends, in part, on the ability of market participants to use the information to draw insights about the behaviour of service providers. The Commission considers that service providers should have to allocate costs and revenues across covered and uncovered pipelines, and each monitored pipeline should have a separate set of accounts (consistent with recommendation 8.6). The service provider has discretion as to the cost allocation method used, but it should be transparent.

Key input and output prices and quantities

Operational statistics could provide some additional information to support the financial statements. The Commission considers that index-based techniques could provide a useful and relatively low cost way of summarising this information. Such techniques have already been used to analyse business performance in telecommunications, rail, and stevedoring in Australia (Lawrence, Diewert and

Fox 2001, Salerian 2003, Lawrence and Richards 2003). The appeal of index-based techniques is that they can make it relatively easy to understand why a service provider's profit has changed over time (box 8.5). Index-based techniques also focus on trend performance. That is, the company's performance is interpreted over a period of time. This can mitigate misinterpretation of variations in performance from year to year. Industry associations representing service providers endorsed a focus on trend performance (the Energy Networks Association, sub. DR85, p. 23; APIA, sub. DR100, p. 30).

Box 8.5 **Possible index-based approach for performance reporting**

Using index-based methods, it is relatively easy to see the extent to which an increase in profit is attributable to higher output prices, as opposed to improved productivity and/or lower costs. This is shown by the example in the following table.

In the example, profit (defined as the ratio of revenue to cost) increased by 6 per cent in year 1. This rise can be attributed to revenue growing faster than costs (16 per cent versus 10 per cent), which occurred for two reasons:

- output prices grew 2 percentage points faster than input prices (7 per cent versus 5 per cent)
- productivity increased by 4 per cent (output quantity grew faster than input quantity — 9 per cent versus 5 per cent).

While the data presented in the table are highly aggregated, it is possible to expand the detail to include individual outputs and inputs.

	Growth				
Index	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*
	%	%	%	%	%
Output quantities	9	…	…	…	…
Output prices	7	…	…	…	…
Total revenue	**16**	**…**	**…**	**…**	**…**
Input quantities	5	…	…	…	…
Input prices	5	…	…	…	…
Total cost	**10**	**…**	**…**	**…**	**…**
Profit[a]	**6**	**…**	**…**	**…**	**…**
Total factor productivity[b]	**4**	**…**	**…**	**…**	**…**

[a] Defined as the ratio of revenue to cost. Equals the percentage growth of total revenue less the percentage growth of total cost. [b] The percentage growth of outputs less the percentage growth of inputs.

Source: Based on the method developed by Salerian 2003.

To implement an index-based technique, it is necessary to determine which individual outputs and inputs should be reported. The data presented in the table in box 8.5 are highly aggregated, however, it is possible to expand the detail to include individual inputs and outputs. Each service provider could submit indices for the whole business. That is, service providers would report an aggregate price index, aggregate cost index, and profit index for the whole business. These indices could then be broken down into detail, for example directly attributable costs to each pipeline and overhead costs. Some examples of inputs (that could be either directly attributable costs or common costs depending on the business structure) that could be reported are labour, overheads, fuel, pipes, compressors, land and easements and gas losses (leaks), however, this would be at an aggregate level. Revenue could be broken down into pipeline and consumer groups at an aggregate level.

Several participants commented that output prices could be disclosed. Goldfields Gas Transmission noted that access monitoring may include monitoring of prices, particularly for the purpose of confirming that discriminatory practices are not being engaged in, but it noted prices should not be the 'sole or primary focus' (sub. DR88, p. 48). APIA considered that 'price monitoring should be applied to core transport services', but noncore services (such as gas park and lend, and backhaul services) should be exempt from the monitoring regime (sub. DR100, p. 33). Epic Energy did not think there should be 'regulatory oversight in situations where the capacity being sold is new and tariffs are a product of market-based negotiations' (sub. DR109, p. 26).

In New Zealand, the information disclosure regulations require service providers to disclose line charges for all consumers. Service providers must also disclose certain details about the contracts they have for conveyance of gas (Ministry of Economic Development 1998). Similarly, airports have to disclose aeronautical and aeronautical-related charges for each service listed in the airports regulations (formerly listed in s.27A of the Prices Surveillance Act). The amount of the per unit charge and the basis of the charge must be disclosed.

Under the proposed monitoring regime for Australian gas pipelines, the Commission considers there should be disclosure of aggregate prices (in levels). The Commission does not envisage disclosure of the price for every service (especially small services). However, where a particular service accounts for a significant amount of the entity's revenue (for example, one service might account for 25 per cent of the revenue of a pipeline) the price for that service should be disclosed.

Dealings with associates

Under the monitoring regime, service providers should have to reveal certain information about dealings with associates. This is to ensure that service providers are not treating their associates more favourably than others, and thereby giving their associates a competitive advantage in upstream or downstream markets.

The monitoring regime for airports requires disclosure of information on related party transactions. However, this only applies to 'material' transactions defined as the aggregate value of transactions in a financial year exceeding whichever is the greater of $100 000 or 0.5 per cent of the turnover of the asset value of the airport operator. In that regime the dealings are included as notes to the financial accounts, specifying:

- the value and nature of the transaction
- details of the related party
- the basis of the price used in the transaction.

Most participants supported disclosure of information on dealings with associates for monitored pipelines under the Gas Access Regime:

> Indicators such as proportion of total volume contracted to affiliated businesses and a measure of tariff deviations may provide the regulator with tools that can assist their assessment and that could be provided transparently to the industry. (ExxonMobil, sub. DR78, p. 6)
>
> [Enertrade supports a process that] ensures that all the relevant details of contracts with associated entities are made public and an undertaking that all those terms and conditions must be made available to any other bona fide pipeline user that requires a materially equivalent service … (Enertrade, sub. DR98, p. 7)
>
> … AGL does not consider that it is necessary to have associate contract requirements approved under the proposed price monitoring regime. Rather, notification would be sufficient. (AGL, sub. DR84, p. 25)

In the context of discussing the voluntary code of conduct proposed by APIA (sub. 44), Epic Energy supported public notification of associate contracts as part of a register of all contracts entered into (sub. DR109, p. 29). Similarly, Goldfields Gas Transmission supported public disclosure of dealings with affiliate entities and like Enertrade suggested:

> … service offerings made to associates would also be available to third party access seekers on similar, nondiscriminatory terms. (Goldfields Gas Transmission, sub. DR118, p. 6)

APIA proposed an arrangement whereby service providers could choose either a commitment to nondiscriminatory access at published terms and conditions, or to regulator approval of any associate contracts (sub. DR100, pp. 56–7).

The Economic Regulation Authority expressed concerns about the need to protect against transfer pricing. It considered this could be done effectively:

> … through the regulator approving service agreements with associates and through the availability of relevant and unbiased comparisons with the profit performance of kindred businesses. (sub. DR116, p. 12)

The Commission considers that it is not necessary for associate contracts to be approved under the monitoring regime. This would give the regulator an unnecessary role in assessing the contract against some criteria of 'appropriateness'. Rather, the Commission considers that information on dealings with associates should be part of the financial and operational statistics information disclosure. For example, total volume contracted to, and total revenue from, affiliated businesses would allow the market to determine whether associates are being treated more favourably than other customers. In addition, the Commission considers an aggregate measure of tariff deviations for affiliates should be provided as part of information on output prices for different monitored pipelines. The method for calculating this measure should be made transparent.

For monitored pipelines, ss7.1–7.6 of the Gas Code (dealing with approval of associate contracts) would not apply. Rather, the information disclosure requirements above would apply.

In relation to the profit performance of affiliated businesses, the Commission notes that such information would be ascertainable from the consolidated accounts that such affiliated businesses are required to provide to ASIC.

Measures of service quality

To complement the financial and operational statistic information, it might be desirable to have transparency of quality of service measures under the monitoring regime. Information on service quality is a potentially useful complement to monitoring of financial and operational information for three reasons:

- To better understand the financial measures. For example, quality of service measures may assist in explaining why costs have increased.
- To provide insights about whether service providers are running down assets or reducing service standards, while maintaining high prices.
- To assist in transparently identifying the effects of upgrades and investment in new facilities.

In New Zealand, the Gas (Information Disclosure) Regulations specify a series of quality of service measures:

- Delivery efficiency measures — load factor, unaccounted for gas ratio, system length, monthly maximum gas entering the system, total amount of gas conveyed, total amount of gas conveyed on behalf of others, and total users.
- Reliability performance measures — planned interruptions, unplanned interruptions, unplanned interruptions resulting from upstream interruptions, number of gas leaks detected by routine service, incidents of damage requiring repairs to the system.

The formulae for calculating these measures are specified in the regulations. Service providers are able to disclose additional explanatory information with these measures (for example, to make a note of random or unforeseen events beyond the control of the service provider that affected performance).

In Australia, it appears as though most service providers already provide information on the quality of their service as part of licensing requirements. There are variations in the organisation responsible for oversight of quality of service measures. It might be:

- the agency responsible for technical regulation (for example, South Australian and Western Australian distribution networks)
- the agency responsible for economic and technical regulation (for example, the ACT and Victorian distribution networks)
- the agency responsible for economic regulation (for example, Queensland distribution networks)
- the Minister (for example, New South Wales distribution networks) (QCA 2003b).

Given these reporting requirements, the Commission is wary about recommending additional quality of service reporting under the proposed monitoring regime. It could be duplicative and costly if service providers are required to submit different indicators of quality of service to different agencies. The Commission considers that it is appropriate to maintain separation of quality of service reporting under technical regulations and economic regulation. This is despite the complementary nature of this information as discussed above.

Disclosure guidelines

A potential problem with monitoring arrangements is ‘regulatory creep’, whereby regulators expand the information burden over time, possibly transforming monitoring into de facto price regulation. The Commission's inquiry on airport services (PC 2002b), concluded that to avoid this problem, the information requirements should be specified at the start of a monitoring period and not amended without agreement of the parties.

In the case of gas pipelines, there should be upfront determination of the data to be reported by the service provider. However, specifying the requirements might not prevent regulatory creep if regulators are responsible for specifying and/or updating them. To reduce incentives for this to occur, it is desirable that the body responsible for developing and updating the information requirements be independent of the regulator undertaking the monitoring function.

In New Zealand, the information required to be disclosed by pipeline owners is specified in the Gas (Information Disclosure) Regulations 1997. These regulations can only be changed by the New Zealand Government. In 2000, the government reviewed the regulations, including a process of submissions from industry participants and interested parties. After the consultation process, the government amended the regulations for the 2000-01 financial year assessment period.

In the draft report for this inquiry, the Commission proposed that the NCC be responsible for developing the Gas Access Regime monitoring guidelines, ideally, through a consultative process that is open and transparent, and includes submissions from interested parties. Several parties were unsure about the NCC fulfilling this role:

> The ENA [Energy Networks Association] does not support the NCC being given responsibility to develop information disclosure guidelines for the price monitoring option. … The ENA considers that … there is a substantial risk that the NCC may develop guidelines that involve a more detailed, intrusive and costly level of information collection than is actually intended by the Productivity Commission to apply under price monitoring. (Energy Networks Association, sub. DR85, pp. 23–4)
>
> … [AGL] has some concern with the Commission's proposal that the NCC could specify and update [the disclosure] guidelines, given that the NCC is not required to, or is experienced in, carrying out this function under its present charter. AGL considers that these guidelines should be developed by the government under a transparent consultative process. (AGL, sub. DR84, p. 27)
>
> … [Goldfields Gas Transmission] has considerable reservations about the latitude given to the NCC in regard to specifying the information disclosure requirements. One aspect of this, might be a tendency to focus on price monitoring to the exclusion of commercially negotiated and flexible access outcomes, if for no better reason than that prices are easily monitored. (Goldfields Gas Transmission, sub. DR88, p. 48)

The NCC (sub. DR92, p. 14) itself questioned whether it has the appropriate expertise to determine what information a service provider should disclose for the purpose of monitoring. The NCC based this conclusion on the inference that the disclosure guidelines would need to include some detail on underlying costs, asset valuations, depreciation, rates of return and prices as well as a range of provisions of third party access. The NCC proposed that the ACCC undertake the task of developing information disclosure guidelines.

The Commission acknowledges participants concerns, but considers the NCC is the appropriate body to undertake the task of developing the guidelines. The Commission notes that it is not proposed that detailed information about the cost base, depreciation or rates of return would form part of the monitoring regime. Rather, the guidance given in this report should provide a basis for the development of guidelines for the monitoring regime, prior to the commencement of the regime. Further, it is envisaged that establishing the guidelines would occur through a public consultation process and the NCC could draw on the evidence and opinions of interested parties. If the NCC was not to be the body responsible for developing the guidelines, then that task would need to be given to another suitable organisation other than the regulator undertaking the monitoring function.

Several participants sought clarification on whether the guidelines would be mere guidelines, regulations or part of the GPAL. Several groups considered it was necessary and appropriate for the disclosure guidelines to be enshrined in legislation because of the penalties proposed for noncompliance (discussed below):

> As a principle of transparent and accountable regulation, ENA [Energy Networks Association] considers that any instruments which create binding obligations underwritten by financial penalties … should be in the form of legislation or legislative amendments. Providing for financial penalties for noncompliance with guidelines issued by a regulatory authority without a clear legislative basis for information collection obligations would be inappropriate. (Energy Networks Association, sub. DR85, p. 24)

The Commission agrees that where compliance penalties apply, there must be a legal basis for the obligations imposed on service providers. However, it is not necessary for the guidelines themselves to be enshrined in the legislation. Rather, the legislation should be drafted to provide guidance for the NCC in preparing the disclosure requirements (similar to the guidance given to the ACCC to develop guidelines for the airports monitoring regime).

The guidelines might need alteration from time to time. The Commission considers such amendments should be made, through a public consultation process, when substantive need arises. The NCC should have responsibility for this role.

The Commission finally notes that the body developing monitoring guidelines might also develop reporting templates. Templates facilitate consistent publication of information and can help to clarify the disclosure guideline requirements.

RECOMMENDATION 8.6

Under the proposed monitoring regime, information disclosure requirements should involve:

- ***focusing more on trend performance, including profitability***
- ***reporting and monitoring after the event, without any need for prior endorsement by the regulator***
- ***the regulator particularly recording cases where access negotiations have been unsuccessful.***

RECOMMENDATION 8.7

To improve regulatory certainty, and reduce the possibility of regulatory creep, information disclosure requirements of the proposed monitoring regime should be set out in disclosure guidelines developed prior to implementation of the monitoring regime. The National Competition Council, or another suitable organisation other than the regulator undertaking the monitoring function, should be responsible for developing this generic set of guidelines. This should involve an open and transparent consultative process. It should be the responsibility of the entity developing the guidelines (the National Competition Council, for example) to update the guidelines when substantive need arises.

FINDING 8.2

The following information could guide the body responsible for developing the information disclosure requirements:

- *Access provision information including number of negotiations commenced in the year, number of negotiations completed resulting in an access agreement being negotiated, number of access negotiations withdrawn from by the access seeker, number of access negotiations withdrawn from by the service provider, number of negotiations in dispute, number of dispute resolution processes commenced and still in progress, and number of dispute resolution processes completed (with an accompanying note about the outcomes of completed dispute resolution processes).*
- *High level financial information (for example, a statement of financial position, a statement of financial performance, and a statement of cash flow that accords with the ring fencing requirements in s.4 of the Gas Code. There should be disclosure of notes to the financial statements and any other information necessary to give a true and fair view.*
- *Operational statistics including quantities and prices for aggregated inputs, quantities and prices for monitored services and the percentage change.*

- *Information on dealings with associates including details of the associates, aggregated total revenue from associates, aggregated total volume sold to associates and an aggregate index of the price deviation for transactions with associates (including disclosure of the index method).*

The Commission envisages monitoring information would be published annually for each pipeline. The information to be reported would not be overly onerous and preferably would comprise information that is already collected by service providers. The information disclosure guidelines would not specify disclosure of the weighted average cost of capital (WACC).

Reporting process

The Commission's inquiry reports on airport services and the *Prices Surveillance Act 1983* (PC 2002b, 2001d) concluded that it was appropriate for a regulator to collate and publish data provided by companies under a monitoring regime. However, any commentary provided by the regulator should be of a factual nature only, rather than assessing the appropriateness of prices:

> Comments by the monitoring agency should be limited to those of a factual or descriptive nature. For example, the agency may wish to comment on the trend in data over the monitoring period or provide a factual comparison with data from the previous monitoring report. This is because … the intent of monitoring is to facilitate information provision, it is not intended to be a form of price control or to entail unwarranted intrusion into the operation of businesses. (PC 2001d, p. 95)

The Economic Regulation Authority noted that their role under monitoring could still be relatively intrusive:

> The regulator's role under the price monitoring regime proposed is not, as yet, well defined. This role might at this stage be taken to span anything from holding casual observer status through to that of engaged advocate for users and prospective users in the pursuit of economically efficient outcomes. (sub. DR116, p. 12)
>
> [Under the monitoring regime, the] public might … reasonably expect the regulator to be in an informed position concerning the prices and associated terms and conditions that are offered by the service provider and alert to discriminatory pricing practices that could operate counter to the principal economic efficiency objective. The regulator will also have to be adequately informed in order to comply with the proposed restriction that only factual information is to be reported by it. (sub. DR116, p. 11)

The Commission is of the view that the regulator's role would be confined to the annual collating and publishing of information submitted by a service provider. There should be a separate publication for each pipeline covered by the monitoring regime. Factual comment, in the case of the Gas Access Regime, would not include any determinations on the appropriateness of costs and prices.

Consistent with the airport services inquiry report (PC 2002b), the Commission envisages that some monitoring data for pipelines might be confidential and thus should be protected by the regulator. The treatment of some data as being confidential will need to be handled on a case-by-case basis. However, as a general principle, the more public the data, the greater is the accountability.

Sections 7.11–7.14 of the existing Gas Code relate to the treatment of confidential information. This section should continue to apply to monitored pipelines (noting that s.7.13 would be irrelevant as it refers to information under cost-based price regulation) enabling service providers to submit confidential information to the regulator on a case-by-case basis.

RECOMMENDATION 8.8

The relevant regulator should collate and publish annually the information disclosed by a service provider under the proposed monitoring regime. Any commentary made by the regulator should be of a factual nature only, for example, the regulator should not make any determinations on the appropriateness of costs and prices.

Compliance measures

The data reported by covered pipelines must be accurate. In the inquiry report on the *Prices Surveillance Act 1983*, the Commission recommended that the chief executive officer (CEO) of the relevant company be required to sign a declaration stating that the monitoring data are true:

> The regulator … would be responsible for ensuring that firms subject to monitoring provide a declaration from the CEO that the information supplied is true and correct. (PC 2001d, p. 94)

The Commission also recommended that the relevant regulator (the ACCC in the case of the *Prices Surveillance Act 1983*) should have the power to seek financial penalties through the courts if companies fail to provide the required monitoring data:

> There should be legislative powers to require those subject to monitoring to provide data, with financial penalties for nonprovision. (PC 2001d, p. 95)

The Commission considers that the abovementioned recommendations should also apply to the monitoring regime proposed for covered gas pipelines.

To add rigour to the monitoring regime, and provide comfort that financial information has been looked at by someone outside the company, the Commission also considers that the service provider should be required to have financial statements and financial performance measures certified by an auditor.

RECOMMENDATION 8.9

To ensure the data disclosed by service providers under the proposed monitoring regime are accurate:

- ***chief executive officers (CEOs) should be required to sign a declaration stating that the data are true***
- ***financial information and financial performance measures should be certified by an auditor***
- ***financial penalties should be available through the courts if companies refuse to provide the required monitoring data within the established deadlines.***

8.6 Other features

Under a monitoring regime, service providers could adopt additional pro-competitive features at their discretion. One option service providers might adopt is a code of conduct detailing minimum standards of behaviour. APIA (sub. 44, p. 71) proposed a code of conduct for uncovered pipelines with the following elements:

- a commitment to open access
- an effective mechanism to ensure that pipelines not subject to the Gas Code are operated in a way that facilitates effective competition
- appropriate ring fencing of pipeline operations (particularly relating to confidential information) from upstream or downstream interests
- the provision of relevant information to the market
- tradeable capacity that can be offered to the market.

Duke Energy International (sub. 21, p. 21) has already adopted a similar code of conduct (nondiscriminatory access policy) for its uncovered transmission pipelines. The policy includes principles similar to those of the proposed APIA code, in addition to commitments to:

- public disclosure of dealings with affiliates
- public disclosure of key contract details
- the use of nondiscriminatory tariffs
- a binding independent dispute resolution process.

The Commission considers that service providers could voluntarily adopt these features under the proposed monitoring form of regulation. However, it has some concerns about the efficiency of nondiscriminatory tariffs. In particular, it might be efficient for service providers to offer volume discounts to increase the throughput of under utilised pipelines. This argument was articulated by the ACCC:

> It is widely accepted that price discrimination among shippers may increase economic efficiency through increased network utilisation. This will particularly be the case for pipelines that are significantly under utilised. Consistent with this the Australian [Gas] Code [s.8.43] explicitly provides for prudent discounts to be offered by shippers. (ACCC 2002a, p. 22)

Duke Energy International, on the other hand, claimed that efficiency would not be adversely affected by a nondiscriminatory pricing policy:

> DEI [Duke Energy International] accepts that in certain circumstances there are efficiency arguments in support of price discrimination. However, DEI does not accept that, of itself, the volume of gas being transmitted through a transmission pipeline represents a circumstance in which there is an efficiency argument for discounting.
>
> … within the gas transmission market, there is no economic justification for the concept of volume discounts. This is because … in the case of gas transmission sales, there is effectively zero economies of scale … In fact, there are probably benefits by diversifying risk across a greater number of customers. (sub. 21, p. 23)

The Commission considers, despite potential efficiency concerns, that service providers should be left to decide whether they adopt a nondiscriminatory tariff policy when subject to light-handed regulation.

Service providers could also commit to PSOs — publishing packages of services, each with differing service standards and associated tariffs — under a monitoring regime. A service provider would offer these packages to all access seekers. Allgas Energy (sub. 25, p. 10 and attachments 2 and 3) provided considerable detail about alternative ways in which to implement a PSO regime. It recommended that the terms of the PSOs be set by negotiation with consumer groups, and that these negotiations be facilitated by some level of information disclosure by the service provider.

A PSO model could form part of the access policy under the proposed form of monitoring regulation. Price and service packages could be developed through negotiations between service providers and consumers, while the outcomes of these negotiations would be subject to the same monitoring oversight as all other types of negotiations.

The Commission considers that codes of conduct, PSOs and other pro-competitive policies might be compatible with the proposed monitoring option. However, it does not consider it necessary to prescribe any of these features. Details of the commercial negotiation process should be left to the negotiating parties, with the regulator monitoring the outcomes of negotiations. Service providers might find that one or more of the models discussed prove useful in demonstrating to the regulator that they have negotiated in good faith and are committed to achieving the objective of the Gas Access Regime.

8.7 Review of the form of regulation

The sections above have set out the Commission's proposed components of the monitoring regime. These components are one part of the monitoring package. Another central requirement of the regime is the process in place for moving from the monitoring regime to the access arrangement with reference tariffs regulation where warranted.

As noted earlier, the Commission considers that the effectiveness of the monitoring regime depends, in part, on the real potential for access arrangement with reference tariffs regulation to apply at some time in the future if monitoring is not effectively moderating behaviour. Key issues to resolve are when access arrangement with reference tariffs regulation can be applied, and the process to be followed to bring this about.

If the regime is designed with the potential for access arrangement with reference tariffs regulation to be applied at any time, the threat is very strong and real. However, such a threat might also create incentive for users to engage in strategic behaviour and stall negotiations to result in heavy-handed regulation. A better alternative might be to make the option of reference tariffs unavailable for a certain period. This could encourage bona fide commercial negotiations between service providers and users, but might also allow service providers greater leeway in the misuse of market power.

The tradeoff between encouraging commercial negotiations by specifying a predetermined period for monitoring and the potential for the misuse of market power was discussed in the Commission inquiry report on airport services:

> There is a need for a credible threat of stronger regulation … If it were made clear, however, that any such regulation would not be reintroduced within a predetermined period, there would be less potential for the undermining of bona fide commercial negotiations. A review at the end of that period could then assess whether stricter forms of price regulation, further monitoring, or any other action were warranted at individual airports. The monitoring period would need to be long enough to encourage commercial negotiation, but not so long that the threat of reintroduction of stricter

> forms of price regulation was not an effective deterrent against abuse of market power. (PC 2002b, p. 324)

Therefore, in choosing the length of the period for allowing unencumbered commercial negotiations, there needs to be the correct incentive structures in place to moderate service providers' behaviour.

In the draft report for this inquiry, the Commission recommended that a Minister's decision in favour of light-handed regulation be binding for five years. In the Commission's view, this period would provide sufficient time for the monitoring regime to facilitate commercial negotiations, while not foreclosing the threat of heavy-handed regulation if there is a misuse of market power.

Service providers generally considered that the threat of heavy-handed regulation in five years was sufficient to prevent the exercise of market power:

> … the Commission has recognised that the heavy-handed option is a sufficiently onerous threat that service providers would normally want to try and avoid having it imposed on them and its sufficient leverage [to] have them behave properly. (Goldfields Gas Transmission, trans., p. 970)
>
> The companies support the Commission's recommendation that the price monitoring would apply for an initial probationary period of five years … The threat of possible reregulation will encourage negotiated pricing outcomes … (Alinta/Multinet, sub. DR91, p. 4)

Several users were concerned about the credibility of the proposed threat:

> … a period of five years would not act as an effective constraint on service provider behaviour and a shorter minimum period is required, potentially coupled with other mechanisms to ensure that this period is not simply used as an opportunity to capture rents. (WMC Resources, sub. DR99, p. 19)
>
> WPC [Western Power Corporation] does not believe that specifying a minimum period during which time no one is able to apply for coverage with price regulation is likely to force users and service providers to negotiate in good faith. (Western Power, sub. DR115, pp. 33 and 38)
>
> The Commission posits that potential resort to a higher level of regulation would operate as a credible threat to service providers to refrain from exercising market power. Worsley does not agree that this is the case, nor does Worsley agree that imposing a five-year period during which no upgrade of coverage can be applied for is likely to promote commercial negotiations between parties … A user would be forced to accept whatever deal it could get during the five-year period because the only alternative is not to enter into any contract for the transmission of gas, which in light of the lack of substitutes, is clearly no alternative at all. (Worsley Alumina, sub. DR110, pp. 14–15)

The ACCC considered monitoring posed a 'weak threat':

> … a minimum five-year period for price monitoring to apply undermines any threat of regulation and consequently the effectiveness of price monitoring. (sub. DR101, p. 60)

Shell had more pragmatic concerns about the fixed five-year period:

> Shell would like to suggest [that the fixed minimum period for monitoring] … be subject to review if competitive factors in a given market change and that the regulator should have the overriding right to step in, in well-defined circumstances. (sub. DR95, p. 4)

On balance, the Commission is of the view that five years is an appropriate period for application of the monitoring regime. This period will allow genuine commercial negotiations to occur, whilst at the same time influencing the behaviour of service providers through the threat of being subject to cost based price regulation at the end of five years.

The Commission's assessment is based on consideration of the obligations imposed on service providers by the total monitoring package. The package is comprehensive, requiring service providers to have an access policy with provisions for binding dispute resolution, be ring fenced, and disclose financial and access negotiation information, and information of dealings with their associates. Section 13 of schedule 1 of the GPAL also applies to monitored pipelines. Thus, users have several options to facilitate commercial outcomes. They can use observations on aggregate price information (for associates and others) to strengthen their bargaining position, they can initiate binding dispute resolution or they can pursue action through the court under s.13 of schedule 1 of the GPAL.

After the five-year period of initial coverage, monitoring should continue, in the absence of a successful application for price regulation. The imposition of heavy-handed regulation would be based on a ministerial decision that the level of market power warranted an access arrangement with reference tariffs (chapter 6). If the Minister decides that monitoring was the appropriate form of intervention, it should continue for another five years (during which there could be no shift to access arrangement with reference tariffs regulation).

Another issue under the monitoring regime, is who should be able to make applications to the NCC for coverage under an access arrangement with reference tariffs. If users of a pipeline covered by the monitoring regime could apply, then costly strategic behaviour might result. In the draft report for this inquiry, the Commission proposed that the relevant regulator (that is, the regulator undertaking the monitoring function) would be in a good position to consider whether a pipeline might be exerting market power and, therefore, apply for coverage under an access arrangement with reference tariffs. Following such an application, the NCC would assess coverage of the pipeline in the usual way, taking into account advice and evidence from the relevant regulator.

Some participants, both service providers and a user, commented on the fact that only the regulator can apply:

> WPC [Western Power Corporation] rejects the suggestion that only the relevant regulator should be able to apply for a pipeline regulated under the monitoring regime to be changed to regulation under the access arrangement regime. While the regulator may be in a good position to make an application, the user is also in a good position, and a user's ability to seek to protect its business interests should not be needlessly restricted in this way. Any user should be able to make such as application, and the Minister, after applying the coverage criteria should be able to judge the merits of the application. (Western Power, sub. DR115, p. 33)

> Envestra supports the Commission's proposed framework [for who can apply for coverage and revocation], with the exception of the involvement of the regulator in movement from a monitoring regime to access arrangement regime. The regulator must be restricted to applying the … regime … (Envestra, sub. DR82, p. 9)

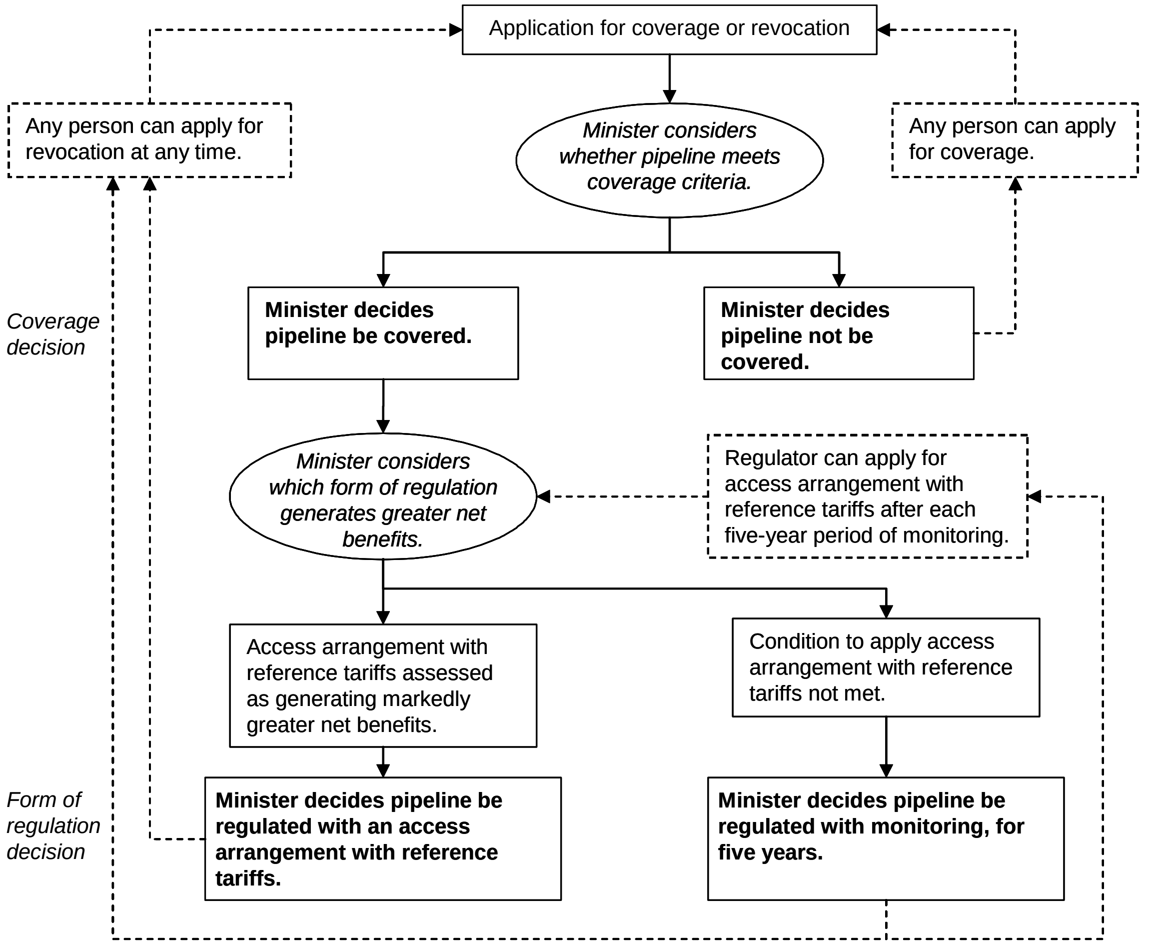
> If price monitoring is adopted, then AGL accepts that there should be a role for the regulator in an application for heavier handed regulation by providing factual material to the decision maker. (AGL, sub. DR84, p. 13)

On balance, the Commission is disposed to limiting applications for movement from monitoring to heavy-handed regulation to the regulator that administers the monitoring regime. This is because the Commission considers that a well-specified monitoring regime should reveal (to the regulator and others) where the service provider is behaving in a way that warrants a review of the form of regulation. In the unlikely event that the monitoring regime does not reveal such behaviour (to the regulator), users would be not be prevented from informing the regulator, via ordinary communication channels, of information on specific pipelines.

An application by the regulator is based on the need to consider whether monitored pipelines require heavier handed intervention. Given the nature of this application, the Commission considers that an application by the regulator to the NCC should be for a review of the form of regulation only, that is, not including a reassessment of the coverage criteria (figure 8.1). As noted above, in the absence of an application, monitoring continues to apply.

In relation to revocation applications for pipelines that are covered with the monitoring regime, the Commission is disposed to maintaining the current arrangements (that is, no restrictions on either when applications can be made, or who can apply) (figure 8.1).

Figure 8.1 **Proposed framework for deciding coverage and form of regulation[a]**



[a] The NCC follows an identical process in recommending to the Minister whether a pipeline should be covered, and if so, what form of regulation should apply.

The Commission considered whether regulators need to be guided on when an application to change coverage to heavier handed regulation is appropriate. It is worth noting observations made in the Commission's report from the inquiry on airport services:

> The potential for inefficiencies may be alleviated to some extent by defining the behaviour on the part of the regulated firm that would trigger stricter forms of price regulation (or, indeed, 'good' behaviour that would not trigger stricter regulation). Nonetheless, clearly defining such behaviour may be difficult — high prices may be a signal that new investment is required rather than an indication that monopoly prices are being charged; high profits may reflect entrepreneurial skills rather than market power, and increases in prices may simply reflect changes in costs or that prices previously were too low. In a capacity-constrained airport, higher prices may be a means to allocate the available capacity efficiently. This suggests that a broad set of principles is likely to be preferable for guiding efficient behaviour to specific criteria that if applied in isolation may not be consistent with efficient outcomes … Specific

criteria for triggering regulatory intervention could also encourage strategic behaviour to this end. (PC 2002b, p. 324)

Consistent with these findings, the Commission considers that it would be inappropriate to prescribe rules on what would trigger a regulator's application to the NCC for heavier handed regulation of a covered pipeline. Rather, the NCC should assess the net economics benefits (chapter 6) and in light of the new evidence available from at least five years of monitoring data.

RECOMMENDATION 8.10

Where the proposed monitoring option is applied, it should apply for a minimum period of five years, during which there would be no shift to access arrangement with reference tariffs regulation. Following this period, monitoring would continue to apply, subject to a decision by the Minister, following a recommendation by the National Competition Council, and an application from the monitoring regulator that access arrangement with reference tariffs regulation should apply. A decision to continue with monitoring would apply for a five-year period. Any person can apply for revocation of coverage of a monitored pipeline at any time.

RECOMMENDATION 8.11

For pipelines that are covered and subject to the proposed monitoring regime, only the relevant regulator should be able to apply to the National Competition Council to shift the form of regulation to access arrangements with reference tariffs.

FINDING 8.3

The effectiveness of monitoring regulation depends in part on the threat of access arrangement with reference tariffs regulation possibly being applied in the future. The service provider's commercial behaviour will be influenced by the threat of being subject to access arrangement with reference tariffs regulation at the end of five years.

8.8 Transitional issues

Several service providers suggested that in implementing the monitoring regime, pipelines be automatically covered under the monitoring option:

… APIA recommends that the existing covered status of existing pipelines be revoked. … APIA … submits that existing pipelines should be covered under … [monitoring] regulation unless the criteria is met for more heavy-handed forms of regulation to be applied. (APIA, sub. DR100, p. 28)

The Commission's proposals for price monitoring could be improved by moving all utilities to a price monitoring regime rather than requiring the National Competition Council to assess, for each company, the case for the application of lighter handed regulation. (Alinta/Multinet, sub. DR91, p. 1)

… the *a priori* assumption should be that regulated companies will produce welfare enhancing outcomes under … [monitoring regulation]. That is 'don't hang them until they hang themselves' by starting companies under … [monitoring regulation] and regulating them … [with cost-based price regulation] if they fail to perform. (Allgas Energy, sub. DR77, p. 5)

It is … appropriate that a price monitoring regime be established as the default standard regime for all networks, with a reference tariff applying only where price monitoring fails. (Envestra, sub. DR82, p. 6)

Enertrade recommends that the two-tiered model consist of light-handed monitoring … and heavy-handed cost of service regulation, the latter being imposed on service providers who, when covered by the light-handed monitoring, are found to have misused market power. … While it may be that gas distribution systems need cost of service regulation as the initial step, transmission pipelines should not be so regulated — at least in the first instance. (Enertrade, sub. DR98, pp. 2–3)

Given the findings of the Commission in relation to the impact of the application of the existing regime on investment and the provision of gas infrastructure to communities, the ENA [Energy Networks Association] considers an appropriate recommendation is that in the initial five-year period following the implementation of the Commission's two-tiered model, all networks and pipelines currently covered should be covered by the price monitoring regime. (Energy Networks Association, sub. DR85, p. 15)

The Western Australian Government thought a case-by-case assessment was appropriate, because it:

… does not envisage that pipelines would have an automatic right to non-price, lighter handed regulation. Any move to implement lighter-handed regulation would need to be based on appropriate criteria. (sub. DR114, p. 10)

As noted in chapter 6, the Commission considers there should be criteria for making a decision on coverage and on the form of regulation. In that chapter, the Commission recommends that the Minister and NCC, in respectively making a decision and recommendation on the form of regulation for a covered pipeline, weigh up the benefits and costs of the two different forms of regulation.

In the Commission's view, this should be the case for the initial implementation of the two-tiered system. At the time the monitoring regime comes into effect, the coverage status and form of regulation should be the same as those applying under the existing regime. Applications for a change in the form of regulation (that is from cost-based price regulation to monitoring) would occur on a case-by-case basis through an application to the NCC for revocation. This application would trigger a decision by the Minister on coverage and, where coverage is retained, the form of regulation. Consistent with the current requirements in the Gas Code, any person can apply for revocation at any stage. This process is depicted in figure 8.1 (commencing in the bottom left-hand corner).

RECOMMENDATION 8.12

Pipelines currently covered with cost-based price regulation should remain covered, and continue to be subject to the access arrangement with reference tariffs regulation. Movement from this price regulation would require an application to the National Competition Council for revocation. Following a recommendation from the National Competition Council, the Minister would make a decision on coverage, and the form of regulation where coverage is retained.

8.9 Certification issues

Certification that the Gas Access Regime is an effective regime within the context of the national access regime is important. Certification by the Minister, following a recommendation from the NCC, ensures the primacy of the Gas Access Regime over the national access regime for covered gas pipelines and prevents regulatory forum shopping (chapter 3).

The NCC, in commenting on the Commission's proposal set out in the draft report for this inquiry, raised issues about whether the proposed Gas Access Regime could be certified as effective. The main issue related to the absence of provisions for negotiation and binding arbitration under the proposed monitoring option:

> … the Commission's current proposal does not meet the requirements of the CPA [Competition Principles Agreement]. In order for an access regime to be certified as effective, clause 6(4)(c) of the CPA requires the access regime to include a means to enforce the access rights granted by coverage … the [National Competition] Council considers that it is essential for any price monitoring regime operating under the Gas Code to include a mechanism for resolving access disputes. (sub. DR92, p. 13)

The Commission recommends that under the monitoring form of regulation, service providers be required to prescribe a framework for commercial negotiation and binding arbitration (section 8.3). Further, as described earlier, it would be possible for the relevant Minister to decide to subject the monitored pipeline to access arrangement with reference tariffs regulation at the end of its five-year monitoring period (section 8.7). Under this latter form of regulation there is already provision for binding arbitration, with the regulator acting as the arbitrator.

The Commission considers it likely that the Minister and the NCC would be able to certify the new regime as effective. However, the situation will remain uncertain until the Minister and the NCC formally consider certification of the new regime.

The Commission has also proposed changes to sections of the Gas Code relating to access arrangements with reference tariffs, such as replacing: factors the regulator must take into account in approving an access arrangement (s.2.24); factors the arbitrator must have regard to when resolving disputes (s.6.15); and factors the regulator must have regard to when determining reference tariffs (s.8.1), with the objects clause and pricing principles (chapters 5 and 7). This could possibly create uncertainty about whether the access arrangements with reference tariffs regime would be certified as effective.

In light of this uncertainty, the Commission recommends that clause 6 of the Competition Principles Agreement be modified as recommended by the Commission in its review of the national access regime (box 8.6). Such a change would make the degree of reliance on negotiation (relative to arbitration and regulation) to set terms and conditions of access a matter for individual regimes and not a part of the effectiveness test.

The Australian Government, in its response to the Commission's report, supported the recommendation to modify clause 6 of the Competition Principles Agreement:

> The Australian Government will work with the States and Territories to consider and progress appropriate changes to clause 6 of the CPA [Competition Principles Agreement]. (Costello 2004, p. 11)

FINDING 8.4

To give primacy to the Gas Access Regime and to reduce forum shopping, it is necessary to have the Gas Access Regime certified as effective under part IIIA of the national access regime. It is likely that the relevant Minister, following a recommendation from the National Competition Council, would be able to certify the new regime effective.

RECOMMENDATION 8.13

To remove uncertainty, pending a decision by the Minister following a recommendation from the National Competition Council that the Gas Access Regime would be certified as effective, clause 6 of the Competition Principles Agreement should be modified as supported by the Australian Government in its response to the recommendation in the Commission's review of the national access regime.

Box 8.6 **Criteria to assess the effectiveness of State and Territory access regimes**

The Productivity Commission in its review of the national access regime found that ideally an ‘effective’ access regime should include the following:

- an objects clause (specifying that the objective of the regime is to promote the efficient use of, and investment in, the essential infrastructure facilities concerned)
- coverage arrangements that focus mainly on services for which it would be uneconomic to develop another facility to provide the service
- clearly specified dispute resolution arrangements and provisions to establish the terms and conditions of access
- clearly specified criteria and pricing principles applying to regulated terms and conditions
- effective appeal and enforcement provisions
- revocation and review requirements for all determinations
- where relevant, provisions to facilitate consistency across multiple State and Territory access regimes applying to a particular service
- where relevant, provision for measures to facilitate efficient new investment.

The degree of reliance on negotiation, relative to arbitration and regulation, to set terms and conditions of access should be a matter for individual regimes and not be a part of the effectiveness test.

Source: PC 2001c, p. 253.

9 Investment and access arrangements

The Commission has recommended the current regulatory approach — access arrangements with reference tariffs — be maintained for cases where it would clearly be more appropriate than the monitoring option outlined in chapter 8. However, a disadvantage of the current regulatory approach is that it has the potential to distort pipeline investment (chapter 4). This distortion can occur as a result of regulatory errors in setting reference tariffs, and the following two effects:

- *Regulatory risk* — the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) can increase the riskiness of investments because, among other things, there is uncertainty about how regulators will use their wide discretion.
- *Asymmetric truncation of returns* — the regime has the potential to truncate investment returns above a certain threshold and therefore discourage investment in pipelines.

Regulators — including the Australian Competition and Consumer Commission (ACCC 2002a) — acknowledge the potential for these investment distorting effects to occur. The key issue is whether a regime involving access arrangements with reference tariffs can be designed so there is an appropriate balance between:

- restraining the misuse of market power
- facilitating efficient investment.

Given that the current regulatory approach — access arrangements with reference tariffs — might continue to be applied to some pipelines, measures to limit the investment distorting effects of regulatory risk and asymmetric truncation are considered in this chapter (measures to reduce the likelihood of regulatory error are examined in chapter 7). The analysis includes a review of the recommendations of relevant past reviews (PC 2001c and EMR 2002) and an assessment of the remedies that the ACCC (2002a) suggested are already available under the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code). The measures are assessed against three broad criteria:

- the extent to which the adverse effect on investment (of regulatory risk or asymmetric truncation) is addressed
- the unwanted side effects that might arise

- the administrative and compliance costs.

9.1 Background to the Commission's assessment

In its review of the national access regime (part IIIA of the *Trade Practices Act 1974*), the Productivity Commission (PC 2001c) discussed several options to minimise the adverse effects of access regulation on investment. The Council of Australian Governments (COAG) Energy Market Review (EMR 2002), chaired by Warwick Parer, also examined such options.

Further, the ACCC (2002a) has published a draft greenfields guideline that seeks to address concerns about the Gas Access Regime's adverse effect on investment in new pipelines. The ACCC considers the Gas Code is sufficiently flexible for it to mitigate the possible investment distorting effects of access regulation, while providing a reasonable rate of return for service providers. The ACCC and NCC (National Competition Council) (2002) have also produced a guide for developing regional transmission pipelines. BHP Billiton noted:

> Both sets of guidelines [greenfields and regional] 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. (sub. 26, p. 74)

However, other participants were sceptical about the value of the ACCC's draft greenfields guideline:

> … nonbinding draft guidelines such as the draft greenfields guideline … issued by the ACCC fail to provide adequate certainty for potential investors in long-lived gas infrastructure. (Energy Networks Association, sub. DR85, p. 25)

> … the ACCC's [draft] greenfields guideline is seen by industry as an abject failure to address any of the issues. It contains nothing to engender confidence in the regime and, in fact, it worsens the widely held perception that the ACCC is defending an entrenched, inflexible and highly biased position. It is also informative that the guideline has not been finalised, remaining only in 'draft' form since it was issued over a year ago. (Goldfields Gas Transmission, sub. 18, p. 9)

> … the realisation and retention (by the service provider) of a share of the 'blue sky' from a successful greenfield project is essentially incompatible with the current structure of the [Gas] Code which is directed towards allowing only efficient costs. For this reason, the draft greenfields guideline cannot provide an appropriate solution. (Australian Gas Light Company, sub. DR84, p. 28)

> The application of the national Gas Code to greenfields pipeline developments remains problematic despite the ACCC's release of its draft greenfields guideline … in June 2002. (Epic Energy, sub. 37, p. 40)

With respect to the draft status of the greenfields guideline, the ACCC stated:

> The fact that the DGG [draft greenfields guideline] is currently a ‘draft’ does not undermine its effectiveness. It is a guide to regulation under the [Gas] Code, rather than a code in itself. The ACCC notes its experience with its mergers guidelines, where the guidelines were in draft form for several years yet provided clear guidance on the ACCC’s processes for assessing merger proposals under the TPA [*Trade Practices Act 1974*]. (sub. DR101, p. 23)

The draft greenfields guideline also maintains the wide discretion that the Gas Code gives to regulators to approve key regulatory parameters. On this point, the ACCC suggested that it is up to service providers to use the flexibility of the Gas Code to their advantage:

> … the ACCC did not intend the draft greenfields guideline to be exhaustive. The responsibility is with the service provider to design an access proposal that best meets its unique needs and circumstances that complies with the principles of the [Gas] Code. (sub. 48, p. 50)

Nevertheless, there is a tension in the Gas Access Regime between providing specific rules and having sufficient flexibility to accommodate the unique circumstances of each pipeline. The ACCC preferred some flexibility under the Gas Code and so its draft greenfields guideline does not seek to remove the discretion currently available to regulators and service providers:

> The discretion … in the DGG [draft greenfields guideline] reflects the provisions of the [Gas] Code. As highlighted by the DGG, discretion is necessary to afford flexibility to service providers with varying requirements in setting regulatory parameters. Moreover, the availability of discretion under the Code does not undermine the potential effectiveness of the DGG because once agreement is reached, the regulator’s discretion is largely bound, providing service providers with a substantial degree of certainty. (sub. DR101, p. 23)

Despite the above comments from the ACCC, the Productivity Commission remains concerned about the lack of regulatory commitment implied by a guideline that has remained a draft for at least two years. The Commission also notes the draft greenfields guideline does not constrain the wide discretion currently available under the Gas Code.

FINDING 9.1

The Australian Competition and Consumer Commission’s draft greenfields guideline does not substantially alter the potential for the Gas Access Regime to discourage investment. This is because the published guideline:

- *is only a draft (and has been so for at least two years)*
- *maintains the wide discretion that the Gas Code gives to regulators to set key regulatory parameters.*

In addition, as detailed below, the mechanisms suggested in the draft greenfields guideline to address regulatory risk and asymmetric truncation can increase complexity and have unintended consequences.

9.2 Options to deal with regulatory risk

Regulatory risk occurs when additional risks are imposed on a project's returns due to uncertainty about a regulator's future behaviour. This increase in project risk, if there is no compensating increase in the expected return of the project, will act as a deterrent to investors.

Envestra quantified the impact of regulatory risk on its operations:

> … in November 2000, JB Were, who is one of Australia's most significant investment institutions, valued Envestra securities at 60 cents. They stated that the company operated in 'a heavy regulated environment' and was exposed to 'regulatory risks'. Once the final decision on Envestra's remaining unapproved South Australian access arrangement was released, the valuation was increased to 80 cents. At this time JB Were stated that the final regulatory ruling gave Envestra an 'increased certainty'. (sub. 22, p. 11)

Two types of regulatory risk faced by investors under the current Gas Code are:

- *coverage risk* — uncertainty about whether a pipeline will be covered
- *parameter risk* — uncertainty about the regulatory parameters that will be applied if a pipeline is covered.

The ACCC (2002a) stated in its draft greenfields guideline that mechanisms already exist in the Gas Code to limit investor uncertainty, including:

- scope for regulators to approve access arrangements of extended duration
- fixed principles that lock in certain regulatory parameters over a long period
- upfront approval of access conditions before construction (if the service provider volunteers to have its pipeline covered).

The options above deal with parameter risk. A common suggestion to reduce coverage risk is to provide binding rulings on coverage before pipeline construction. This is currently not possible under the Gas Access Regime. This issue and the abovementioned options are examined below.

Extended access arrangement periods

Section 3.18 of the Gas Code allows regulators to approve an access arrangement period of any length. However, if the period is longer than five years, then a regulator must consider whether mechanisms should be included to deal with cases where the forecasts used to determine an access arrangement prove to be incorrect. The Gas Code states that such mechanisms may include:

- a trigger mechanism that requires a service provider to submit revisions to its access arrangement if certain events occur (for example, if profits fall outside a prespecified range)
- a benefit sharing mechanism that involves service providers returning some revenues or profits in excess of a certain amount to users.

The Commission understands that regulators typically approve access arrangements with a five-year life span:

> … the industry benchmark for the length of a proposed access arrangement has become a five-year period. (WMC Resources, sub. 43, p. 10)

One exception was the ACCC's decision for the Central West Pipeline (Marsden–Dubbo pipeline). BHP Billiton (sub. 26, p. 71) noted this decision provided for a 10 year access arrangement and thus enabled benefits from better than forecast cost reductions to be kept for up to 10 years.

Epic Energy was sceptical about the benefits of extended access arrangement periods:

> Regulator concern to ensure zero economic profits in the short term means that [the Gas] Code provisions permitting longer regulatory periods are of little relevance. (sub. 37, p. 2)

WMC Resources raised concerns about how trigger mechanisms could dilute the increased certainty associated with an extended access arrangement period:

> The practical problem which … arises is whether these arrangements are such as to, in substance, provide no more than a five-year regulatory arrangement. If that is the effect of the arrangement then, given the long-term nature of the investment, it provides little comfort to pipeline investors. (sub. 43, p. 41)

The Australian Gas Association (sub. 13, p. 11) noted that an average gas distribution network might be subject to 13–15 regulatory price reviews (or resets) over its operational life, assuming a typical access arrangement period of five years. This raises a question about how the most appropriate duration for an access arrangement is ascertained. In this regard, the Allen Consulting Group commented:

> … 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 [Gas] Code contemplates a regulatory period of generally no more than five years, although … [it allows] for longer regulatory periods subject [to] mechanisms to address risks in forecasting being considered. The five-year period reflects the standard practice of the UK energy and water regulators. (BHP Billiton, sub. 26, attachment, p. 34)

The ACCC noted:

> … debate about the appropriate length of the regulatory period … is largely a result of attempting to allow sufficient time for a firm to retain any gains above the building block reference tariffs while seeking to ensure that prices reflect efficient costs. It is considered that a five-year access arrangement period strikes the right balance in most instances. (sub. 48, p. 37)

On balance, extended access arrangement periods have the potential to decrease the risk of regulators changing behaviour once a pipeline is covered. However, having review mechanisms in access arrangements of extended duration could offset some of the increased certainty about a regulator's behaviour. Further, under the existing Gas Access Regime, investors cannot know with certainty whether their proposed pipeline would be covered. Hence, extended access arrangement periods are unlikely to address the investment distorting effects of the existing regime, except in cases where coverage is volunteered by a prospective pipeline investor. A recommendation later in this chapter to introduce binding no-coverage rulings prior to investment might overcome this concern to some extent.

FINDING 9.2

Extended access arrangement periods might reduce the risk of unforeseen changes in regulatory parameters (parameter risk). However, the extent to which risk is reduced depends on the types of review mechanisms that regulators require in an access arrangement of extended duration.

Fixed principles that lock in certain regulatory parameters

The Gas Code allows some components of a reference tariff policy to be locked in for longer than a single access arrangement period (ss8.47–8.48). These components are termed fixed principles and are limited to structural elements. Structural elements are reference tariff calculation principles and methods that do not vary with changing market conditions and that are structured for longer than a single access arrangement period. They include the depreciation schedule and the assumed financing structure. Elements that cannot be locked in as fixed principles include sales forecasts, real interest rates, and capital and noncapital costs.

An example of the application of fixed principles is the ACCC (2000a) decision for the Central West Pipeline. This decision allowed a depreciation schedule that under recovers in initial years to build demand and then recovers losses with higher tariffs later. BHP Billiton (sub. 26, p. 71) commented that the decision allows the service provider to capitalise early losses so it can recover those losses once demand grows.

Fixed principles have also been approved by the Victorian Essential Services Commission (ESC 2002b) for Victorian distributors (Envestra, Multinet and TXU Australia). For example, their access arrangements contain fixed principles that include a commitment that:

- until the end of the next access arrangement period:
  - incentive based regulation using a CPI-X price cap will be adopted, rather than rate of return regulation
  - the capital asset pricing model (CAPM) will be used to calculate the rate of return on the capital base, if the rate of return is relevant to the determination of reference tariffs
- for 30 years from the commencement of the access arrangement, the value of the capital base at the start of the access arrangement period will not be reduced as a result of assets becoming redundant.

Fixed principle provisions are unlikely to increase regulatory risk and might, to a limited extent, reduce risk for investors. However, given the uncertainty associated with setting regulatory parameters, there is a possibility that having a fixed principle will lock in a regulatory error for an extended period. This possibility might cause regulators to err on the side of caution by requiring regulatory parameters that are less advantageous for a service provider. In addition, the extent to which regulatory risk is reduced by a fixed principle depends on the fixed period allowed by a regulator and on which parameters can be fixed.

FINDING 9.3

Fixed principle provisions that allow some regulatory parameters to be locked in for a certain period have the potential to reduce the risk of future changes in a regulator's behaviour (parameter risk). However, the extent to which risk is reduced is limited. The extent of risk reduction depends on the fixed period allowed by regulators and on which parameters can be fixed.

Binding rulings on coverage before construction

The term 'binding ruling' is used here to refer to a ruling on coverage prior to the commitment to invest in a new pipeline. Such a ruling would be made using the coverage criteria and processes. The duration of the binding coverage ruling could be determined on the basis of one of the following:

- a fixed period after the new pipeline commences operations
- until specific criteria, such as a certain cumulative level of profit, are met
- until circumstances are judged to have changed in such a way as to warrant revocation of the ruling.

A binding coverage ruling has the same effect as a regulation free period (discussed in section 9.3), if a ruling is made in favour of no third party access regulation for a certain period without conditions after the regulation free period has been granted.

Currently, service providers can seek an opinion from the NCC on whether a proposed pipeline would meet the coverage criteria. However, the NCC's advice is nonbinding. A number of inquiry participants argued that making such advice binding would go a long way to addressing concerns about coverage risk. The Australian Gas Light Company (AGL) claimed:

> The introduction of binding upfront coverage rulings will substantially remove the element of regulatory uncertainty for greenfields pipelines, particularly marginal projects. (sub. 32, p. 21)

Similarly, the Australian Gas Association said:

> … facilitating a capacity to obtain upfront binding rulings on proposed capital investment would be a positive way to ensure that over the medium to long term unnecessary regulatory risk is removed. (sub. 13, p. 69)

The NCC also favoured the introduction of binding coverage rulings to increase investor certainty about coverage. However, it cautioned about the difficulties of making such a ruling:

> … there would be difficult issues to consider. Primarily, these issues would revolve around the extent to which the [National Competition] Council — or any other body charged with the task — would be in a position to form an opinion on relevant matters. This would necessarily depend on the circumstances of each application and the information provided to that body. (sub. 57, p. 68)

Duke Energy International raised concerns about the timeliness of binding rulings:

> … the process of obtaining a binding ruling, which is likely to include public consultation and the possibility of an appeal, may be costly and would almost certainly introduce delays in the development of the pipeline project, to the detriment of the

> future development of the market. Once a binding ruling has been obtained, this option would result in greater certainty (as it lasts the life of the asset) compared to a regulatory free period. (sub. 21, p. 35)

The ACCC stated that binding rulings might have merits but questioned whether they were the best way of reducing coverage risk:

> The ACCC believes that there may be benefits from reducing the uncertainty of potential pipeline investors through binding upfront rulings by the NCC regarding coverage. However, there is an inherent conflict … between providing certainty to potential investors in transmission pipelines and the need for the decision maker to be able to change the coverage status of a pipeline if circumstances change over time. On this basis, the objective may be better achieved through the DGG [draft greenfields guideline] processes.
>
> An example of such an occurrence would be a change in ownership of a pipeline that results in an increase in horizontal or vertical integration. This may alter the ability of the owner to exercise market power such that the coverage criteria would be met. (sub. DR101, p. 53)

Both the review of the national access regime (PC 2001c) and the COAG Energy Market Review (EMR 2002) favoured the use of binding rulings.

The Gas Access Regime could be amended so the relevant Minister, after receiving advice from the NCC, could provide a binding no-coverage ruling, using the revised coverage test proposed in chapter 6. Such a ruling would reduce regulatory uncertainty and therefore might cause otherwise marginal pipeline investments to proceed.

Binding no-coverage rulings do not, however, address all the potential investment distortions caused by regulation. Incentives might still exist to build smaller pipelines than otherwise so there is no spare capacity that can be subject to reference tariffs (chapter 4). However, the introduction of the light-handed monitoring option would somewhat mitigate incentives to undersize a pipeline. Under the current regime, the incentive to undersize pipelines is linked to cost-based price regulation. Under the proposed coverage test (chapter 6), the incentive to build a smaller pipeline would be reduced because the likelihood that an access arrangement with a reference tariff is required would be lower.

Operationalising binding no-coverage rulings

If the relevant Minister, on advice from the NCC, decides not to issue a binding no-coverage ruling, then the investor can seek to have an access arrangement approved before construction, to further reduce uncertainty (discussed later).

Alternatively, the investor might choose to construct the pipeline and then wait to see whether an access seeker applies for coverage.

If the relevant Minister, after receiving advice from the NCC, rules that a prospective pipeline would not be covered, then this decision would bind the Minister to provide the pipeline with this status for some period after construction.

In determining the duration of a binding no-coverage ruling, there is a need to balance the considerations of certainty for the investor, while providing for a change to the regulatory treatment of the project if circumstances change materially.

The review of the national access regime (PC 2001c) recommended that binding rulings continue to apply until revoked by the Minister on advice of the NCC of a material change in circumstances. This would have had the same effect as extending the current coverage treatment of existing pipelines under the Gas Access Regime to proposed investments.

In contrast, Duke Energy International supported granting binding no-coverage rulings for the life of a pipeline:

> In the absence of access holidays, DEI [Duke Energy International] supports the introduction of binding upfront coverage decisions on the proviso that the decision lasts for the life of the pipeline asset. (sub. 21, p. 37)

The COAG Energy Market Review (EMR 2002) claimed that the possibility of revocation of binding rulings would reduce the certainty created by such rulings. However, it recognised that a regulator would be reluctant to grant a binding ruling without the possibility of revocation in the future. To overcome this issue, it proposed introducing binding coverage rulings for a fixed period without the possibility of revocation, unless the information relied on proved to be false or intentionally misleading.

The Commission accepts the arguments of the COAG Energy Market Review that the relevant Minister, on advice from the NCC, should grant binding no-coverage rulings for a defined period. This would provide certainty for investors while balancing the need for the regulator to be able to change the status of the pipeline in the longer term, if circumstances change. However, too short a period would not reduce uncertainty significantly for service providers and could have other adverse implications (such as on financing and refinancing).

The COAG Energy Market Review (EMR 2002) claimed a 15-year no-coverage ruling would be sufficient, in most instances, to deliver a rate of return to make an investment profitable. It also claimed that a pipeline not meeting the coverage criteria at the time of a ruling is unlikely to do so after 15 years, because markets would be expected to become more competitive over time.

Service providers and their industry associations argued that a 20-year period was more appropriate for binding no-coverage rulings:

> From its understanding of commonly used project financing guidelines the ENA (Energy Networks Association] considers that a 20-year period of noncoverage would be more appropriate due to the potential for a 15-year period to result in significant regulatory truncation of the upside of any successful projects. The ENA considers that any period of binding noncoverage that was shorter than 15–20 years would almost certainly represent little improvement over the current regime, as the binding period of coverage would cover only the typical period of early losses experienced by greenfields developments. (ENA, sub. DR85, p. 25)
>
> … APIA submits that a 20-year holiday period is superior to a 15-year holiday period on account of the following factors:
>
> - in modelling pipeline economics (that is the basis upon which project revenue requirements are determined, as distinct from project financing which might conceivably be based on the assumption of a 20-year loan life with subsequent refinancing anticipated after this), periods well in excess of 20 years (rather than 15 years) are routinely utilised. The duration of the mechanism must also pay particular regard to addressing (at least in part) the truncation issue which generally emerges only towards the end of the economic life of a pipeline
> - too short a holiday period runs the risk of access holidays only operating during the loss-making period — when demand for access is low in any case — with regulation being potentially introduced when the investment is proven at which point access seekers will want to share in the blue sky
> - for taxation purposes, 20 years was the period agreed for depreciation of pipelines. The 20-year period ultimately determined for transmission tax depreciation purposes reflected the outcome of an intense debate on the appropriate balance — recognising the need for a simple and effective solution — and the same values and principles should be reflected as the ‘floor’ for the economic regulation free period. (APIA, sub. DR100, pp. 49–50)
>
> Origin’s experience is that … [pipeline] projects are financed over a period of 20 years rather than … 15 years. (Origin Energy, sub. DR83, p. 2)

The Northern Territory Treasury argued that binding no-coverage rulings of up to 25 years might be required for new pipelines built in relatively small and developing markets:

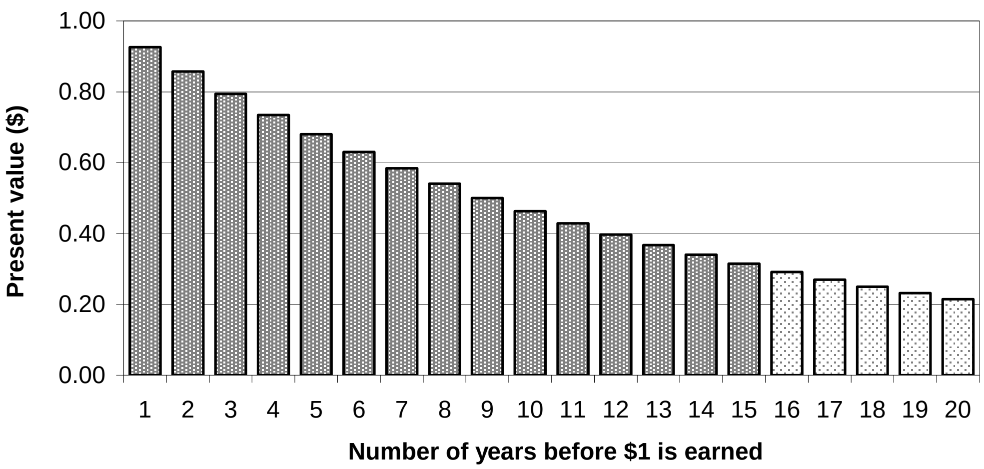
> Investment horizons for gas pipeline infrastructure in relatively small and developing markets are often considerably longer than 15 years and can be as long as 30 years … As such, [the Northern Territory] Treasury urges the Commission to consider the merits of longer no-coverage binding rulings (up to 25 years) in cases where a greenfields pipeline is to supply small and isolated demand centres: where thin markets and isolation provide significant barriers to effective upstream/downstream competition

emerging in the medium to long term; and where the transportation of gas would provide a comparatively efficient form of energy. Treasury contends that such a mechanism would provide additional impetus to investment in new pipeline infrastructure in the Northern Territory. (sub. DR126, p. 2)

The Commission is not convinced that the investment distorting effects of coverage risk would be markedly reduced by extending the length of binding no-coverage rulings from 15 to 20 or more years. Investors are unlikely to undertake a risky investment if they expect its viability to depend largely on earnings that occur more than 15 years into the future. The considerable uncertainty associated with forecasts would cause prudent investors to attach a relatively small weight to returns that are expected to occur well into the future.

In addition, a dollar earned (with certainty) more than 15 years into the future has a much smaller 'present value' than a dollar earned (with certainty) before 15 years, due to the effects of discounting. Figure 9.1 illustrates this using a discount rate of 8 per cent, which is close to the weighted average cost of capital (WACC) approved, on average, by regulators under the Gas Access Regime, as reported by IRIC (2003, p. 41). Another way to understand the impact of discounting is as follows — to earn $1 in present value terms, an investment has to generate a level of revenue at 20 years ($4.66) that is 1.5 times greater than that at 15 years ($3.17) and more than double that at 10 years ($2.16) (assuming a discount rate of 8 per cent).

Figure 9.1 **The present value of $1 earned in the future[a]**



[a] Based on a discount rate of 8 per cent.

A Minister might find it difficult to make binding no-coverage rulings that preclude coverage for as long as 15 years. As noted above, the NCC (sub. 57, p. 68) expressed concerns about whether it would be in a position to judge the difficult issues involved in a coverage application for a proposed pipeline. In addition, the asymmetry of observed outcomes might cause any organisation assigned the task of making binding no-coverage rulings to err on the side of caution. That is, the coverage decision might be influenced by the possibility that failing to cover a pipeline with market power is easier to observe than a wrong decision to cover a pipeline with no market power. The Commission considers that this problem can be addressed by having the relevant Minister and NCC guided by the revised objectives recommended in chapter 5 and coverage test recommended in chapter 6. The Commission considers, therefore, the introduction of binding no-coverage rulings would constitute an improvement on the current situation.

Given the above, the Commission has concluded that a binding no-coverage period of 15 years, rather than 20 or more years, would be sufficient to address the distorting effect of coverage risk on greenfield investments. After 15 years of operation, a pipeline that had a binding no-coverage ruling could become covered if there is a successful coverage application. If the relevant Minister decides that an access arrangement with reference tariffs is warranted, then it will be necessary to value the service provider’s pipeline. This would be done in accordance with s.8.13 of the Gas Code.

RECOMMENDATION 9.1

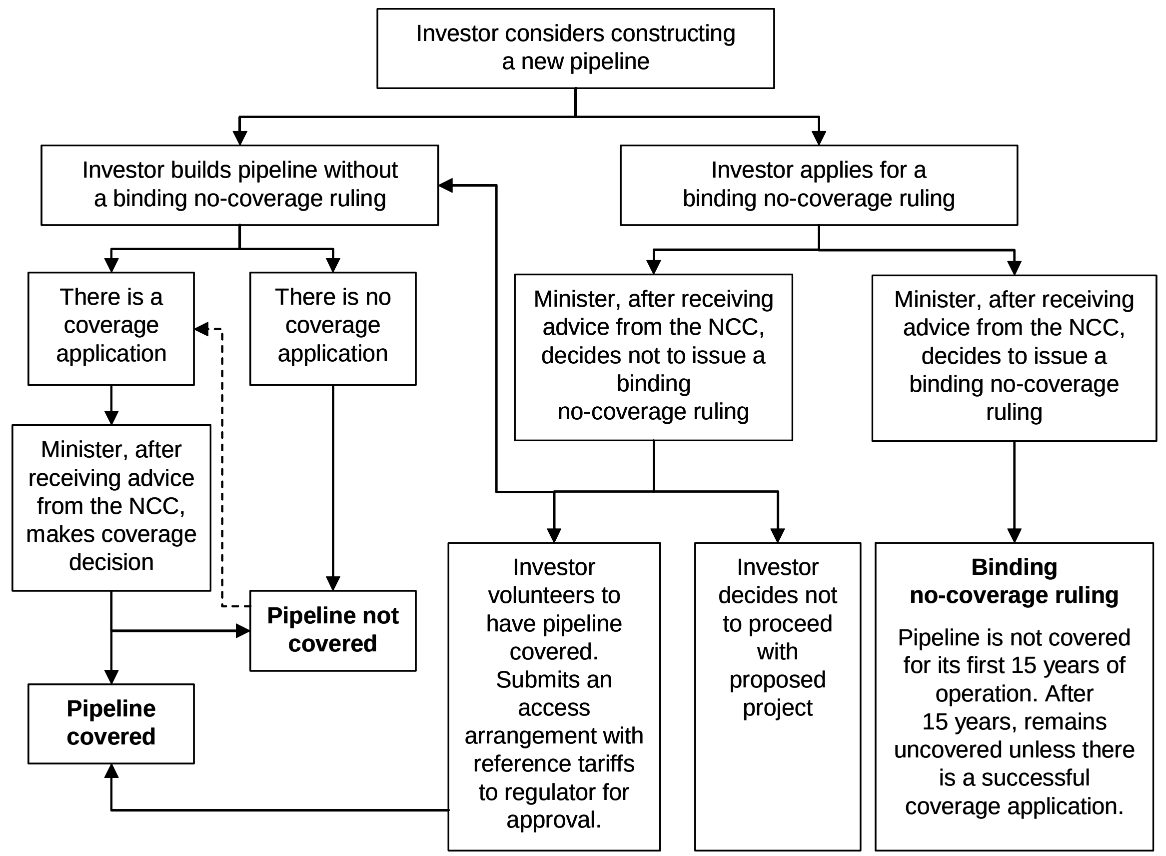
The Gas Access Regime should be amended so that the relevant Minister, after receiving a recommendation from the National Competition Council, can provide a binding no-coverage ruling for a proposed pipeline if it does not meet the coverage criteria. A binding no-coverage ruling should remain in effect for 15 years from when the pipeline commences operations, unless the information relied on by the relevant Minister or National Competition Council was intentionally misleading. After 15 years of operation, a pipeline that was subject to a binding no-coverage ruling should continue to remain uncovered unless there is a successful coverage application.

A potential problem with binding no-coverage rulings is that they would not remove the possibility of being declared under the national access regime (part IIIA of the Trade Practices Act). This is because the existing national access regime treats all uncovered pipelines as being eligible for declaration. The value of binding no-coverage rulings would be undermined by the possibility of being declared. Therefore, the Commission considers that the national access regime should be amended so that pipelines granted a binding no-coverage ruling under the Gas Access Regime cannot be declared.

RECOMMENDATION 9.2

If recommendation 9.1 is implemented, then the national access regime (part IIIA of the Trade Practices Act 1974) should be amended so that a gas pipeline cannot be declared while it is subject to a binding no-coverage ruling under the Gas Access Regime.

Figure 9.2 **Proposed coverage pathways for new pipelines[a]**



[a] A new pipeline can also be covered via the competitive tendering provisions of the Gas Code.

Another concern is that a change of ownership can occur within the 15-year period of a binding no-coverage ruling, and this could markedly increase a service provider's market power (such as a merger with a competing pipeline operator). One way to address this would be to allow binding no-coverage rulings to be revoked if a pipeline's circumstances changed. However, this raises difficult questions about how to identify a change of circumstances that is sufficiently large to warrant reconsideration of a binding no-coverage ruling. The Commission considers the best approach is to deal with concerns about ownership changes through other means. For example, there are sections of the Trade Practices Act that deal with mergers and a refusal to supply.

Figure 9.2 illustrates the possible coverage pathways for a new pipeline if binding no-coverage rulings were made available.

Access conditions approved before construction

The Gas Code allows investors to submit an access arrangement for approval prior to the completion of the relevant pipeline:

> If a Pipeline or *proposed Pipeline* is not Covered, a Service Provider may apply to the Relevant Regulator for approval of an Access Arrangement by submitting the proposed Access Arrangement to the Relevant Regulator together with the applicable Access Arrangement Information. For the purposes of a proposed Access Arrangement submitted under this section 2.3, the term 'Covered Pipeline' in the Code includes a Pipeline or *proposed Pipeline* the subject of the proposed Access Arrangement. (Gas Code, s.2.3) (emphasis added)

This interpretation seems to have been supported by the ACCC (2002a) in its draft greenfields guideline:

> A service provider or prospective service provider can volunteer that a pipeline be subject to the provisions of the [Gas] Code by proposing an access arrangement to the regulator for approval. Following the regulator's approval the pipeline is covered from the date that the access arrangement becomes effective until any specified expiry date (ss1.20 and 2.3 of the Code).
>
> The ACCC considers that the Code has been drafted with the clear intention of accommodating access arrangements for prospective pipelines. (ACCC 2002a, p. 8)

However, BHP Billiton expressed some doubt that access arrangements can be approved before construction:

> … the only specific problems with the [Gas] Code that the industry has identified are of the nature of technical shortcomings — such as confirming that regulators have the ability to approve an access arrangement in advance of a pipeline being built. BHPB [BHP Billiton] would support amendments of this nature. (sub. 26, pp. 78–9)

Epic Energy also raised doubts about the scope for an access arrangement to be approved for a proposed pipeline:

> The [Gas] Code still acts only to facilitate a regulatory decision after a new pipeline has been constructed. (sub. 37, p. 40)
>
> The tariffs that might be obtained through the process of regulation need to be known by both the new pipeline owner and prospective shippers … [within about 12 months of project initiation] … so that they can conclude their negotiation of foundation contracts. However, the earliest opportunity for regulatory approval under the national Gas Code is some two to three years later. This creates major difficulties for new pipeline development. (sub. 37, p. 43)

In any case, the Gas Code does enable access conditions to be approved in advance if reference tariffs are determined in a competitive tender. As detailed in chapter 7, problems have been experienced in implementing this aspect of the Gas Code. Under current regulatory arrangements, pipeline investors can also submit an undertaking using part IIIA of the Trade Practices Act.

Where a proposed pipeline does not involve a competitive tender, investors are unlikely to volunteer to have an access arrangement with reference tariffs, given:

- the substantial costs associated with having an access arrangement with reference tariffs (chapters 4 and 7)
- the reluctance of investors to divulge publicly the detailed information required to have an access arrangement approved, while they are still engaged in negotiations with prospective foundation customers.

Further, the Commission's recommendation to introduce binding no-coverage rulings would remove the need for investors to volunteer coverage. Rather, they would have an incentive to apply to the NCC for exemption of their proposed pipeline from coverage for a given period.

FINDING 9.4

Approval of an access arrangement (including reference tariffs) before construction could reduce the risk of future changes in a regulator's behaviour (parameter risk). However, pipeline investors would be unlikely to seek to be subject to a regulator approved access arrangement with reference tariffs, given the costs and time involved and the information disclosure requirements.

9.3 Options to deal with asymmetric truncation

As noted in chapter 4, asymmetric truncation occurs when regulation limits upside returns and does not involve an equivalent truncation of downside returns. It can discourage investment by reducing the expected rate of return for a proposed pipeline. In its draft greenfields guideline, the ACCC (2002a) claimed that such investment distorting effects can be mitigated using mechanisms that are already possible under the Gas Code, including:

- the symmetric truncation of returns (using sharing mechanisms)
- review triggers to limit downside returns
- extended duration access arrangements
- fixed principles

- service provider initiated reviews.

The review of the national access regime (PC 2001c) and the COAG Energy Market Review (EMR 2002) noted the following options to mitigate the effects of asymmetric truncation:

- truncation premiums
- regulation free periods.

This section examines the effectiveness of the abovementioned measures in mitigating the investment distorting effects of asymmetric truncation.

Truncation premiums

Adding a 'truncation premium' to the *ex ante* regulatory rate of return for new pipelines might address the adverse effects of asymmetric truncation. A truncation premium seeks to give back (by means of a higher price) what a regulator takes away (through regulatory resets or benefit sharing mechanisms that truncate upside returns).

It is useful to note the distinction between a risk premium and a truncation premium. The former provides an incentive to risk averse investors to invest in more risky projects, while the latter compensates for the asymmetric truncation of returns under regulation.

In some cases, regulators have recognised the need to compensate investors in greenfield projects for the higher risks involved. The ACCC (2000a) allowed a higher post-tax nominal return on equity for the Central West Pipeline in recognition of the pipeline facing greater risks than those of an established pipeline. Similarly, the Independent Pricing and Regulatory Tribunal (IPART 2000) allowed a risk premium in the *ex ante* regulatory rate of return for AGL's distribution system in New South Wales to compensate for the possibility of capital being declared redundant. Nevertheless, truncation premiums have yet to be introduced in an access arrangement, despite regulators acknowledging the potential for asymmetric truncation (ACCC 2002a).

Goldfields Gas Transmission offered support for a truncation premium, noting:

> … the 'truncation premiums' identified by the [Productivity] Commission in regard to addressing the Gas Code's contribution to investment risk, primarily address the first order investment risk (that is, that new investment will not occur at all). (sub. 18, p. 11)

However, this support depended on the terms of implementation of the truncation premium:

> For industry to have any confidence in such an approach, very clear guidelines would be needed as to how to determine such premiums, and in what circumstances they would apply. (Goldfields Gas Transmission, sub. 18, p. 33)

The Australian Pipeline Industry Association (APIA) expressed reservations about a truncation premium, claiming:

> … the provision of a truncation premium will also represent a complicated case-by-case approach to the problem. (sub. 44, p. 94)

Gans and King (2003) argued against a truncation premium, claiming regulators would not commit beforehand to a truncation premium that would later apply, given the legal, political and practical constraints on regulators. These constraints could include community concerns that high returns are a sign the regulator has failed to prevent monopolistic behaviour. Similarly, Gans and King (2004) argued:

> Because regulatory commitment [an inability of regulators to commit to access prices prior to an investment being made] lies at the heart of the truncation problem, claims that the problem can be avoided by simply raising the allowed access price [via a truncation premium] … are true but trivial. If the regulator could commit to sufficiently high access prices then there would not be a truncation problem. (Gans and King 2004, p. 93)

APIA also expressed doubts about a truncation premium because of a lack of regulator commitment:

> … the very need for a fixed premium principle to be specified highlights the dangers of leaving the setting of such a parameter in the hands of regulators. If the regulatory processes undertaken to date effectively incorporated the risks facing new investments, there would be no need for such recommendations to be made.
>
> Consequently, APIA does not have any confidence that the current regulatory system would be able to deliver a sufficient premium absent any legislated or mandated provision quantifying its extent. (sub. DR100, p. 50)

Envestra observed:

> While the introduction of a truncation premium is laudable, there is a danger that regulators will compensate for this in other areas, that is, rely on the truncation premium as a panacea, instead of adequately assessing risks and uncertainties in relation to service providers’ investments. (sub. DR82, p. 10)

The Commission acknowledges that a truncation premium could, in theory, address the distortionary impact of asymmetric truncation on investment. However, significant implementation issues would have to be addressed before the introduction of such a premium. To calculate project-specific premiums, a regulator would require knowledge about the distribution of returns, as well as some explicit estimate of the extent to which the regulator expects to limit the upside potential of such returns. As detailed in the review of the national access regime (PC 2001c), such an approach would entail some degree of regulator subjectivity and, as such, might become an additional source of gaming and disputation between the regulator and the service provider.

The review of the national access regime (PC 2001c) raised the possibility of introducing a fixed (standard) premium across all investments. The arguments of Cooper and Currie (1999) were used to highlight the practicalities of such an approach:

> In principle, the correct way to deal with this problem is to adjust the expected cash flows by the impact of the asymmetric clawback provision. In practice it is unlikely to be easy to make the necessary adjustment in this way as it would involve estimating the probabilities of events about which, by their nature, the regulator must be uncertain. In reality, therefore the adjustment is likely to take place by an *ad hoc* adjustment to the cost of capital that evolves over time and with experience. (Cooper and Currie 1999, p. 31)

While a fixed premium would be imprecise relative to a case-by-case approach, it would have several advantages relative to the project-specific method. First, a fixed premium would be administratively simple, because it could be clearly stated in the Gas Code that the regulator must apply a given upward adjustment to the WACC to compensate investors for the truncation of returns. Second, a fixed premium would eliminate the incentives for gaming by the service provider, because it would eliminate the potential for the service provider's claims or behaviour to influence the size of the premium. Finally, introducing provisions for a fixed premium in the Gas Code might address the concern of Gans and King (2003, 2004) that regulators would be unable to provide an *ex ante* commitment to such a premium. Nevertheless, there is a risk that a fixed premium would distort investment incentives more than a project-specific premium that recognises the unique features of an investment.

Another concern is that by providing a truncation premium, a regulator might feel obliged to truncate upside returns, because users have paid a premium for it (Kolbe, Tye and Myers 1993, p. 55). However, the Commission considers that asymmetric truncation would occur regardless of whether it is formally acknowledged in a premium.

In the Commission's view, a fixed truncation premium could go some way to addressing the truncation problem, by moving the expected rate of return of a project in the direction of the expected rate of return without asymmetric truncation. As such, a fixed premium might facilitate investment relative to the current truncated returns scenario and impose little additional burden on the regulator.

The key issue with introducing a fixed truncation premium is how such a premium could be implemented within the framework of the Gas Code. One option is to have a fixed proportionate upward adjustment in the *ex ante* regulatory rate of return for a project. Under this approach, the magnitude of the resulting premium would depend on the project's beta or risk relative to the market. A drawback of this approach is that asymmetric truncation affects the distribution of total returns, rather than just the returns associated with systematic (nondiversifiable) risk (appendix B).

In addition, a truncation premium could be difficult to implement because there is a complex interaction between the extent of truncation and the rate of return required by investors. Appendix B applies the CAPM (which is typically favoured by regulators) to a numerical example to demonstrate that this complex interaction occurs because truncation changes the:

- expected return of an investment
- dispersion of an investment's possible returns (risk)
- correlation between an investment's expected return and that of the market portfolio of all risky investments.

The Commission raised the possibility of a truncation premium in its draft report and sought participants' views on how it could be implemented.

The Western Australian Government noted that it:

> … considers that imposition of a truncation premium may be a second best solution. It is attempting to compensate for the risk of regulatory error by imposing further regulation. Hence, it may be preferable to investigate more market-based solutions, such as incentive mechanisms. (sub. DR114, p. 3)
>
> The truncation problem is founded in the regulators' inability to commit to access prices that allow an investor an appropriate return to cover all relevant *ex ante* risk. Regulators do not know the true project risk and there is a tendency for investors to exaggerate risk in order to prop up the regulated access price. In this situation the regulator is unable to commit to such prices and an alternative mechanism for accommodating investor risk must be applied.
>
> As a result, the imposition of a truncation premium may be a second-best solution. It is attempting to compensate for the risk of regulatory error by imposing further regulation. Hence, it may be preferable to investigate more market-based solutions such as incentive mechanisms. (sub. DR114, p. 13)

AGL observed:

> The truncation premium proposal would appear to require some development and refinement. Apart from the issue of quantification, it is not clear which classes of investment would be entitled to the premium. AGL assumes the Commission does not intend the premium to be available to all 'new pipelines'. For example, it is arguable

> that a pipeline constructed to serve an established gas market is not subject to the same level of truncation risk as one that is built to bring gas to a new undeveloped market. (sub. DR84, p. 31)

The Commission has concluded that truncation premiums are a less than ideal solution to the problem of asymmetric truncation, given the difficult implementation issues involved. Most notably, it would be hard to determine the appropriate level of a truncation premium (a potential new source of regulatory error). The numerical example presented in appendix B illustrates the complex empirical issues involved. Another question is which projects should receive a premium. Truncation premiums could be restricted to only the riskiest greenfield projects because they have a very wide distribution of possible returns and hence are the most likely to be distorted by asymmetric truncation. An alternative option would be to allow truncation premiums for all new investments, including extensions and expansions of existing pipelines. Given the problems with truncation premiums, the Commission has decided not to recommend their adoption.

FINDING 9.5

Adding a fixed premium could address the asymmetric truncation of returns to some extent. A fixed premium would be a low-cost mechanism to promote investment, given its low administrative costs and the limited scope for strategic behaviour. However, it involves difficult implementation issues, such as the level of the premium and whether it should be restricted to riskier greenfield projects.

Symmetric truncation (benefit/loss sharing)

Symmetric truncation transfers some of the downside risk of a pipeline to its users, to counteract the impact of truncating upside returns. This is similar to the concept of profit sharing, which is discussed in the incentive regulation literature (Vogelsang 2002). To understand the mechanics of symmetric truncation, it is useful to first consider the related concept of benefit (upside) sharing.

Benefit (upside) sharing

Benefit sharing occurs when some of the benefits of greater than forecast demand and/or efficiency improvements are redistributed from service providers to users. A benefit sharing mechanism defines what proportion of benefits are transferred to users and also the threshold at which benefit sharing commences:

> A benefit sharing mechanism would involve the inclusion of a methodology for the sharing of greater than expected revenues between the service provider and users, and

may also identify an event that will invoke the benefit sharing provisions. (ACCC 2002a, pp. 27–8)

With respect to thresholds, the ACCC envisaged that a:

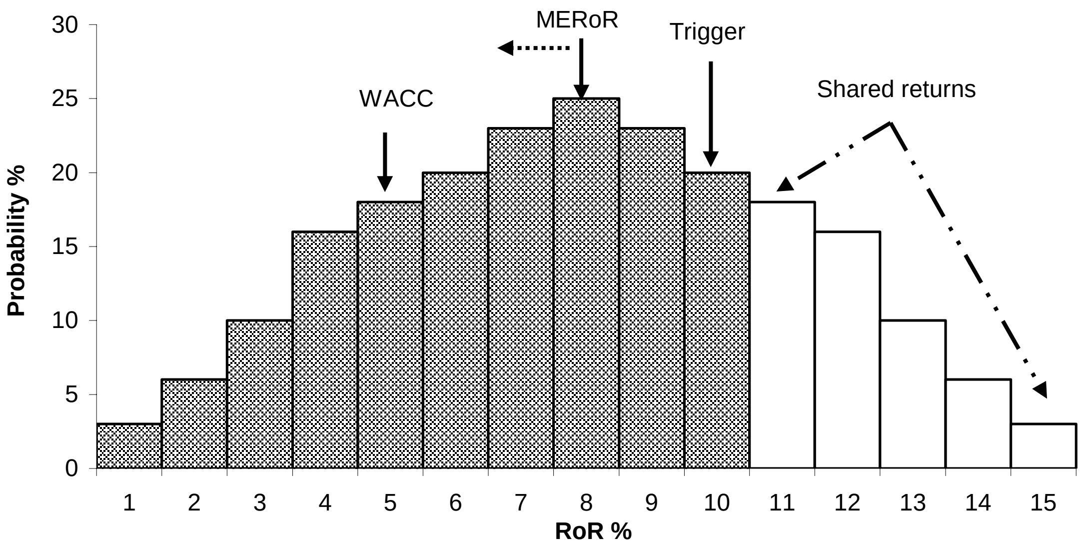
… benefit sharing mechanism would only come into operation after the prospective service provider has been adequately rewarded for undertaking the investment … (ACCC 2002a, p. 28)

Benefit sharing can result in asymmetric truncation, because upside returns are potentially curtailed beyond a certain threshold whereas downside returns are not. Depending on where the threshold is set, benefit sharing can reduce the expected rate of return for a proposed pipeline, which in turn can discourage investment.

The ACCC acknowledged in a diagram in its submission — reproduced here as figure 9.3 — that benefit sharing reduces the expected rate of return (the mean expected rate of return (MERoR) shifts to the left in the figure). However, it did not perceive this as being a major problem:

The benefit sharing mechanism does result in the MERoR [mean expected rate of return] moving to the left of the *ex ante* MERoR [mean expected rate of return without benefit sharing]. However, the amount of sharing above 10 per cent [in figure 9.3] would be *ex ante* known to the pipeline developer and the ACCC is mindful of the need to allow a MERoR equal to or above the project WACC. (sub. 48, p. 62)

Figure 9.3 **ACCC diagram illustrating how benefit (upside) sharing reduces the expected rate of return[a]**



[a] MERoR = the mean expected rate of return. WACC = the weighted average cost of capital. Trigger = the threshold point beyond which benefit (upside) sharing occurs. RoR = rate of return.

Source: Figure 5.6 from ACCC, sub. 48, p. 63.

The ACCC considered that a benefit sharing mechanism can negate the truncation problem, because investors know in advance how greater than expected returns will be treated:

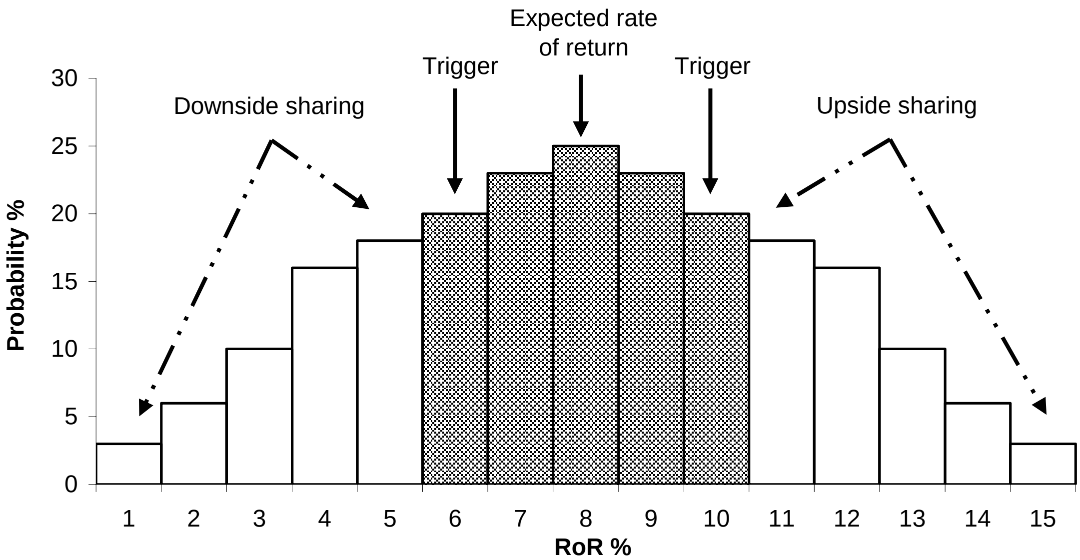
> Depending on the amount of sharing, the service provider has *ex ante* certainty as to the *ex post* regulatory effect on actual returns which are higher than the MERoR [mean expected rate of return] thus negating the 'truncation problem'. (sub. 48, p. 62)

However, this confuses the benefits of knowing what the rules are — namely, lower regulatory risk — with the adverse effects of those rules, such as the investment distorting effects of asymmetric truncation. The extent of this problem increases as upside returns are increasingly truncated.

Downside (loss) sharing and symmetric truncation

It is theoretically possible to adopt a downside sharing mechanism that counteracts the adverse impact of benefit (upside) sharing on a pipeline's expected rate of return. Downside sharing involves some of the losses from less than forecast demand and/or efficiency improvements being transferred from service providers to users. If there is a symmetric distribution for the rate of return, then combining downside and upside sharing results in symmetric truncation when the downside and upside trigger points for sharing are the same distance from the expected rate of return. This is illustrated in figure 9.4, which is a modified version of the ACCC diagram presented in figure 9.3.

Figure 9.4 **Symmetric truncation (downside and upside sharing)[a]**



[a] Trigger = threshold point beyond which downside or benefit (upside) sharing occurs. RoR = rate of return.

Source: Productivity Commission modification of figure 5.6 from ACCC, sub. 48, p. 63.

The key characteristics of symmetric truncation are:

- the redistribution of downside losses from service providers to users — this occurs if the actual rate of return is more than a given proportionate distance below the expected rate of return
- the redistribution of upside benefits from service providers to users — this occurs if the actual rate of return is more than the proportionate distance above the expected rate of return (assuming a symmetric distribution for the rate of return).

This is similar to profit sharing or sliding scale regulation in which customers share in a utility's excess profits or profit shortfalls (Vogelsang 2002). While upside/downside sharing could be triggered when a pipeline's actual rate of return is above or below a certain level, the ACCC (2002a) noted that triggers could also be defined on the basis of one of the following:

- demand volume
- revenue
- profit
- a combination of the above.

If a trigger is defined using one of the above variables, then there will nevertheless be an impact on the actual rate of return.

In its draft greenfields guideline, the ACCC (2002a, pp. 51–5) provided an example where benefit/loss sharing applied if sales were one standard deviation above or below the average sales forecast (box 9.1).

How downside returns are truncated

In principle, greater than forecast returns can be shared with users by reducing reference tariffs when upside returns occur. However, sharing the losses from less than forecast returns is more problematic. If reference tariffs were increased when downside returns became apparent, then this would probably put additional downward pressure on a service provider's returns. This result would occur because higher prices are likely to reduce sales even further below those forecast. Recognising this problem, the ACCC (2002a) stated:

> …. capitalisation of financial losses is the preferred mechanism. This enables a more satisfactory return to be achieved even in a black sky [downside] scenario but over a longer timeframe. (ACCC 2002a, p. 29)

Box 9.1 ACCC example of a symmetric sharing mechanism

In its draft greenfields guideline, the ACCC (2002a) proposed the following 'symmetric sharing mechanism':

- if actual sales are one standard deviation higher than the average forecast used to determine the terms of an access arrangement, some of the resulting benefits are transferred to customers
- if sales are one standard deviation below the average forecast, then some of the resulting losses are transferred to customers.

The ACCC did not specify how benefits/losses would be shared between service providers and users. Rather, it suggested doing so on a case-by-case basis. It mentioned the following options:

- adjust tariffs for the year ahead if deviations from forecast demand can be anticipated in advance
- provide rebates to customers at the end of the year if demand cannot readily be anticipated
- adjust the capital base to reflect the over/under recovery of the expected revenue target, which is then factored into the calculation of reference tariffs in the next access arrangement period.

The ACCC claimed that the choice of mechanism is more a matter of practicality rather than a matter of regulatory principle.

The ACCC (2002a) elaborated on its preferred downside sharing mechanism (capitalisation of losses) by noting:

> … an [upward] adjustment could be made to the residual value of the asset base to reflect the … under recovery of revenues … [Then] the revenues are subsequently recovered in future regulatory periods after the next regulatory review … This is similar to the economic depreciation approach proposed for the Central West Pipeline where loss or under recovery of revenues because of low demand in early years is compensated by capital appreciation of the regulatory asset base to allow eventual recovery when the market matures. (ACCC 2002a, p. 55)

By capitalising losses, a service provider would defer sharing those losses with users until future access arrangement periods. This approach assumes that greater than expected returns eventuate some time in the future, from which losses can be covered.

Interaction with the ex ante *regulatory rate of return*

As noted in chapter 7, the determination of reference tariffs requires regulators to decide what is an appropriate *ex ante* regulatory rate of return for a pipeline. Regulators typically calculate this expected rate of return using the CAPM.

It could be argued that the CAPM implies that the regulatory rate of return should be reduced when there is symmetric truncation. The CAPM assumes that the expected rate of return demanded by investors for a particular investment depends on that investment's beta. A beta measures how an investment's returns vary relative to a market portfolio of all risky investments. The beta for an individual pipeline is a function of the:

- variability of the pipeline's returns
- variability of the market portfolio's returns
- correlation between the returns of the pipeline and the market portfolio.

As the variability of a pipeline's returns fall, so will its beta and thus the expected rate of return required by investors (assuming no change in the variability of the market portfolio's returns and their correlation with the pipeline's returns). In other words, as a pipeline investment becomes less risky, the expected rate of return demanded by investors could fall.

As noted above, appendix B uses a numerical example to demonstrate that, under the CAPM framework, there is a complex interaction between the extent of truncation and the rate of return required by investors. This is because truncation changes not only risk and the expected return, but also the correlation between an investment's expected return and that of the market portfolio of all risky investments.

Nevertheless, symmetric truncation will make pipeline investment less risky, because sharing downside and upside risks with users reduces the variability of a pipeline investor's returns. According to the CAPM, therefore, symmetric truncation can reduce a pipeline's beta and, by implication, the expected rate of return required by investors. This implies that symmetric truncation might have to be accompanied by a reduction in the regulatory rate of return. Otherwise, investors would be overcompensated for their (reduced) risk. This is analogous to the original monopoly problem that regulatory intervention was meant to prevent.

The Gas Code requires regulators to take account of a pipeline's risk when considering the regulatory rate of return:

> The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk

involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service). (Gas Code, s.8.30)

It could be argued that the above section of the Gas Code requires regulators to reduce a pipeline's *ex ante* regulatory rate of return when it approves a symmetric truncation mechanism. This assumes that it is possible to transfer risk from service providers to users.

'Incentive regulation' and risk

The risk reduction that results from sharing mechanisms highlights a tension that regulators face in applying the Gas Code.

Regulators have acknowledged that the 'incentive regulation' approach typically used in applying the Gas Access Regime creates greater risk for service providers than would traditional regulatory methods, such as cost of service regulation. In particular, the use of price (growth) caps that, in the short term, decouple reference tariffs from a service provider's costs, creates a risk that service providers will earn lower or higher profits than expected (chapter 7). From a regulator's perspective, the increased risk associated with incentive regulation might be justified because service providers have a stronger incentive to increase efficiency than they would under cost of service regulation. Nevertheless, regulators have also recognised the tension that incentive regulation creates between encouraging efficiency gains and increasing risk. As a result, they have indicated an interest in using sharing mechanisms to mitigate the risk resulting from price caps.

For example, the (Victorian) Essential Services Commission (ESC) noted:

> … [regulatory approaches that provide] incentives (rewards) to firms for operating efficiently and revealing efficient costs through their behaviour … are referred to as 'high powered' incentive schemes because they decouple allowed prices from a firm's actual costs, at least for a period of time. Accordingly, regulated businesses bear a greater degree of risk in relation to changes in their cost structures than under 'low powered' incentive schemes such as cost-plus, rate of return regimes.
>
> … high-powered regulation does not impose the same returns on all firms and it does not create explicit links between returns and risks. Such a direct link would be consistent with a cost-based, and therefore low-powered, regulatory scheme.
>
> Regulators may … face a tradeoff with respect to incentives and risk. As noted, high-powered incentive regimes create stronger performance incentives but also entail greater risk. Low-powered regulation reduces incentives but also mitigates risk. (sub. DR112, pp. 7–8)

> Earnings sharing mechanisms … are widely seen as devices that mitigate shareholder risk, although these lower risks are also accompanied by lower performance incentives. (sub. DR112, p. 16)

In its draft greenfields guideline, the ACCC (2002a) highlighted how service providers can share risk with users under the Gas Code by adopting a symmetric sharing mechanism. A numerical example was provided to support this observation:

> This example is based on a demand-focused volume threshold. … [The] sharing mechanism would only be initiated once a predetermined volume threshold had been reached. … [The] ACCC envisages that such a threshold would be set such that the prospective service provider would realise and retain the blue sky benefits it identified as potentially realisable in deriving its expected demand, before the benefit sharing provisions took effect.
>
> It should also be noted that the sharing mechanism … is symmetric in that the costs to the pipeline developer of abnormally low demand is diminished with potential users of the pipeline sharing those costs in higher future tariffs. (ACCC 2002a, p. 28)

The ACCC also noted there is a tradeoff between providing incentives to service providers and meeting the expectations of users:

> … the challenge for regulators is to assess access regime proposals that establish a framework which ensures the service provider's economic incentives to maximise utilisation of its assets and development of its business while not imposing unreasonable cost transfers to users. (ACCC 2002a, p. 26)

Feasibility of symmetric truncation under the existing Gas Code

The ACCC (2002a, p. 18) considered that sharing downside and upside returns is feasible under ss8.44–8.45 of the Gas Code, which enable regulators to approve an incentive mechanism as part of an access arrangement. An incentive mechanism permits service providers to retain at least some of any returns 'that exceed the level of returns expected' for a given period (although returns *below* expectations are not mentioned in ss8.44–8.45). The period over which excess returns are retained might be for more than a single access arrangement period.

The ACCC expressed a preference for access arrangements to include an incentive mechanism that shares upside returns:

> The ACCC considers that the inclusion in an access arrangement of a threshold point from which benefit sharing should occur is desirable. (sub. 48, p. 52)

The key issue is where the threshold point is set. The ACCC noted the Gas Code provides considerable flexibility regarding the details of an incentive mechanism:

> There is a range of benefit sharing mechanisms that a prospective service provider could consider when formulating an access arrangement. … Possible trigger events

> could be based on demand, revenue, profit or a combination of these. (sub. 48, pp. 52–3)

Like many other aspects of the Gas Code, this high level of flexibility might be contributing to investor uncertainty.

Tension between incentive mechanisms and remedies for asymmetric truncation

Section 8.46 of the Gas Code states that an incentive mechanism should be designed with a view to achieving certain objectives (box 9.2). The objectives include providing an incentive to minimise costs, increase sales, and develop new services. Remedying the investment distorting effects of upside truncation is not specified as an explicit objective of incentive mechanisms. Envestra observed:

> The objective of an incentive mechanism is to provide an incentive to improve efficiency, not ameliorate the truncation of returns caused by the [Gas Access] Regime. (sub. 22, p. 39)

Box 9.2 Objectives of an incentive mechanism

Section 8.46 of the Gas Code states:

> An Incentive Mechanism should be designed with a view to achieving the following objectives:
>
> (a) to provide the Service Provider with an incentive to increase the volume of sales of all Services, but to avoid providing an artificial incentive to favour the sale of one Service over another
>
> (b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services
>
> (c) to provide the Service Provider with an incentive to develop new Services in response to the needs of the market for Services
>
> (d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non Capital Costs, and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non Capital Costs for the purposes of sections 8.16(a) and 8.37 and
>
> (e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation or volume of sales occur).

Another concern is how symmetric truncation might interact (or possibly conflict) with incentive mechanisms that are designed to meet the objectives listed in s.8.46 of the Gas Code. An example of the latter might be the efficiency carryover mechanisms approved by the ACCC (2002b), ESC (2002b), and South Australian Independent Pricing and Access Regulator (2001) in recent years. Such mechanisms enable service providers to keep the benefits of lower than forecast costs for a time beyond the current access arrangement period (box 9.3).

Envestra claimed that efficiency carryover mechanisms do not remedy asymmetric truncation:

> Rewards for efficiency and truncation of returns are two separate issues. Efficiency carryover mechanisms should reward efficient behaviour and not seek to remedy other deficiencies in the [Gas Access] Regime, such as truncated returns. Efficiency carryover mechanisms have not overcome any concerns about regulators truncating returns. (sub. 22, p. 39)

The carryover mechanism approved by the ACCC (2002b) for GasNet Australia might increase a service provider's downside risk (as well as increasing potential upside returns). This outcome arises because unanticipated increases in operating costs are carried forward for a certain period, rather than being covered by higher reference tariffs (box 9.3). The ACCC noted:

> While it is possible that an automatic carryover may harm the interests of the service provider in the short term, the Commission [ACCC] does not consider that these costs outweigh the benefits to users and efficiency … (ACCC 2002b, p. 284)

The Commission's assessment

The use of a symmetric truncation mechanism seems relatively straightforward at a conceptual level. However, the discussion above indicates numerous practical issues are involved, including the following:

- Both symmetric truncation and efficiency carryover mechanisms would be implemented under the incentive mechanism provisions of the Gas Code, but they could have opposing effects. Symmetric truncation reduces risk (as measured by the range of possible returns), whereas efficiency carryover mechanisms can increase risk.
- It appears that the incentive mechanism provisions of the Gas Code were intended to provide incentives for improved efficiency, rather than to remedy defects of the Gas Access Regime, such as the investment distorting effects of asymmetric truncation.
- It could be argued that the CAPM framework (and possibly s.8.30 of the Gas Code) requires symmetric truncation to be accompanied by a lower *ex ante* regulatory rate of return. However, lowering the regulatory rate of return seems to defeat the purpose of truncating symmetrically (to ensure truncation does not reduce a pipeline's expected rate of return).

Box 9.3 **Efficiency carryover mechanisms**

Efficiency carryover mechanisms enable service providers to keep the benefits of lower than forecast costs for a certain length of time beyond the current access arrangement period. Without such a mechanism, service providers have an incentive to exploit their informational advantage relative to regulators by delaying efficiency gains until after the next access arrangement review (so imminent efficiency gains do not result in lower reference tariffs at the access arrangement review).

In recent years, efficiency carryover mechanisms have been approved in access arrangement decisions by the ACCC (2002b), ESC (2002b), and South Australian Independent Pricing and Access Regulator (2001). Envestra noted such mechanisms are also being considered by the Queensland Competition Authority:

> … recently efficiency carryover mechanisms have been implemented under the Incentive mechanisms section of the [Gas] Code (s. 8.44). These reward businesses for incremental cost reductions into the next access arrangement period. … The incremental efficiency carryover mechanism is well defined in the Victorian access arrangement. The South Australian Independent Pricing and Access Regulator chose to provide a set of guiding principles in the South Australian Access Arrangement and the QCA [Queensland Competition Authority] is in the process of developing an efficiency carryover mechanism for the Queensland networks. (Envestra, sub. 22, p. 38)

The incentive mechanisms approved by the ESC (2002b) allow the automatic carrying forward of benefits from lower than forecast operating and capital costs, but not losses. It decided the automatic carryover of losses was inappropriate because:

> … it may dampen incentives to make efficiency gains in the next [access arrangement] period, since any such gains would be offset by the negative amount carried over. (ESC 2002b, p. 166)

The ESC (2002b, p. 165) also noted carrying forward losses might threaten the financial viability of service providers. This is because reference tariffs would not be adjusted upwards when unanticipated cost increases occur. The ESC decided that it would judge any accrued negative carryover amount on a case-by-case basis at the end of an access arrangement period.

In contrast, the ACCC (2002b) required GasNet Australia to adopt a carryover mechanism for operating costs (and not capital costs) that involves the automatic carryover of losses as well as gains. The ACCC (2002b) disagreed with the ESC's view that losses should not be automatically carried over, because not carrying forward losses would create a gaming opportunity for service providers:

> Under a mechanism that does not require the retention of losses, the service provider has an incentive to claim a gain in one year, and to shift expenses to the following year and claim a loss. (ACCC 2002b, p. 272)
>
> … an automatic negative carryover will not harm incentives and will provide some certainty regarding the application of … benefit sharing … A negative carryover simply represents a penalty for being less efficient … While a … negative carryover will … decrease … the service provider's revenues in the subsequent access arrangement period, it will not influence the sharing of future efficiencies and thus the incentive for gains within that period. In addition, a mechanism that is not characterised by an automatic negative carryover may generate an incentive for the service provider to game the regulator, potentially creating inefficient outcomes … (ACCC 2002b, p. 284)

There might also be problems with how downside returns are truncated. As noted previously, the ACCC (2002a, p. 29) has stated that 'capitalisation of financial losses is the preferred mechanism' to mitigate downside risk. This approach would defer the sharing of losses until future access arrangement periods. On the surface, this seems a sensible approach, since sharing losses (by increasing prices) when sales are below forecast would probably reduce returns further.

However, investors might not view the ability to capitalise losses as reducing their downside risk. The redundant capital provisions of the Gas Code mean that capitalising losses does not guarantee those losses can be recovered in the future. Indeed, if sales are below forecast, then it seems more likely that a service provider's capital will be made redundant at a future access arrangement review.

It should also be noted that, under the building block approach, capitalising losses will change the time profile of regulatory depreciation and by implication reference tariffs. The question then arises as to whether the resulting reference tariffs are consistent with s.8.1(d) of the Gas Code, which states:

> A Reference Tariff … should be designed with a view to achieving … efficiency in the level and structure of the Reference Tariff …

There is also some doubt about whether capitalising losses would meet the new pricing principles recommended in chapter 7. For example, using regulatory depreciation to recover (indexed) downside returns (as well as indexed historic capital costs) does not appear to be consistent with setting prices to recover the efficient cost of an investment. In summary, there appears to be a conflict between the principle of efficient pricing and the use of depreciation to recover past losses from users.

Another concern is that the timing of depreciation and hence the recovery of capitalised losses seems to be arbitrary:

> … the time path for depreciation can be viewed as arbitrary. As long as the rate of return on the residual RAB [regulatory asset base] value at any point in time is expected to be achieved, the NPV [net present value] of expected cash flows will equate to the RAB. (ACCC 2001a, p. 10)

Hence, it is theoretically possible for two competing pipelines to recover their capitalised losses from users at different points in time. By implication, reference tariffs could differ between the two pipelines in a particular period, which might distort pipeline usage and lead to inefficient outcomes.

There are additional concerns about symmetric truncation:

- It will probably add to the complexity of the current building block approach, as the depreciation profile might need to be altered many times.

- The threshold points beyond which sharing occurs are arbitrary. The example used by the ACCC (2002a, pp. 51–5) in its draft greenfields guideline was that benefit/loss sharing should apply if sales are one standard deviation above or below the average sales forecast. The ACCC did not indicate why these threshold points were selected.
- Transferring risk to users in order to remedy a defect of the Gas Access Regime raises the question of what is the appropriate sharing of risk between:
  (a) users and service providers
  (b) today's users and future users (since losses would be capitalised).
- The method used to share benefits appears to be arbitrary. Possible mechanisms include rebates and lower future reference tariffs. The ACCC (2002a, p. 55) claimed that 'the choice of mechanism is more a matter of practicality than being a matter of regulatory principle'. However, it seems unlikely that different mechanisms will lead to identical responses from users.
- The timing of benefits or losses precedes sharing. This might distort investment if time preferences differ between investors and the regulator.

FINDING 9.6

A benefit/loss (symmetric) sharing mechanism is not a satisfactory means of mitigating the investment distorting effects of price regulation from truncating upside returns. Such a mechanism shifts both downside and upside risk from investors to users. Even if such a risk transfer was considered appropriate, benefit/loss sharing mechanisms would be subject to a wide range of practical problems.

Service provider initiated reviews

Section 2.28 of the Gas Code enables a service provider to submit revisions to its access arrangement at any time. The ACCC (2002a) claimed this mitigates the downside risk faced by service providers:

> These provisions afford protection to a prospective service provider in the event that unforeseen factors affect it and constrain its ability to earn a reasonable return. … Thus, service provider initiated, unscheduled revisions to an access arrangement can assist a service provider who finds unforeseen factors significantly impinging on its ability to earn a reasonable return. (ACCC 2002a, p. 25)

Because regulators do not have as much flexibility to initiate revisions, the ACCC labelled service provider initiated reviews an 'asymmetric review' mechanism that biases regulatory outcomes.

> These provisions … asymmetrically bias expected outcomes in favour of the service provider. (sub. 48, p. 60)

However, regulators do have some scope to initiate an early access arrangement review via s.3.17(ii) of the Gas Code. This section states that a regulator might require an access arrangement to define ‘specific major events’ that trigger an obligation on the service provider to submit revisions before the revisions submission date. The ACCC termed these ‘off ramps’:

> An ‘off ramp’ describes the circumstances under which the approved access arrangement could be opened for review by the regulator, in effect triggering a reassessment of reference tariffs. ‘Off ramps’ are intended to safeguard users against excessive pricing by the service provider and protect the firm from financial distress in adverse economic circumstances. (sub. 48, p. 38)

Goldfields Gas Transmission was sceptical about the scope for service provider initiated reviews to mitigate risk:

> … just because a service provider initiates an early access arrangement review, this does not guarantee … that the revised arrangement will be accepted. It merely means that he places himself afresh upon the mercy of the regulator. The service provider has no certainty that the proposal he makes will not then be rejected in favour of something which might even worsen his situation … (sub. 18, p. 10)

To illustrate its concerns, Goldfields Gas Transmission noted the ACCC (2002a, p. 29) has stated that ‘capitalisation of financial losses is the preferred mechanism’ to mitigate downside risk:

> No mention is made of the redundant capital provisions of the Gas Code, against which the service provider has no protection other than the regulator's economically defined good graces. Similarly, no mention is made of the view that the shareholders in the investment at risk might take of the regulator's unbounded ability to determine their cost recovery strategy. (sub. 18, p. 9)

The Commission’s assessment

There appears to be merit in maintaining the right of service providers to seek revisions to their access arrangement at any time. This approach might limit the damage resulting from regulatory error. It is also appropriate to continue to subject a service provider’s proposed changes to regulator assessment.

Service provider initiated reviews do not directly address the problem of asymmetric truncation. Rather, the logic appears to be that investment is not distorted because the potential truncation of upside returns is balanced by possible truncation of downside returns through a service provider initiated review. This is similar in concept to the symmetric sharing mechanism examined above, since a limit on downside returns could raise the expected rate of return for a proposed pipeline up to the *ex ante* regulatory rate of return. Again, a problem arises because the beta used by regulators to set the regulatory rate of return becomes inconsistent with the reduced variance of returns caused by limiting downside risk.

The nature of downside risk mitigation is far less certain with service provider initiated reviews than it is with a symmetric truncation mechanism. This is because the outcomes of access arrangement reviews are uncertain, whereas symmetric truncation mechanisms have specific rules and trigger points for initiating downside risk mitigation. Even if the behaviour of regulators is known with certainty, investors might not consider the right to initiate a review justifies a notably higher expected rate of return. For example, the ACCC's preferred mechanism of capitalising losses into the capital base does not guarantee those losses can be recovered in the future.

FINDING 9.7

It is appropriate for service providers to have the right to seek revisions to their access arrangement at any time if demand is lower than forecast. This limits the damage caused by regulatory error. However, service provider initiated reviews are not an effective mechanism for addressing the investment distorting effects of asymmetric truncation.

Regulation free periods

Regulation free periods allow new pipelines a period free from regulatory intervention. Delaying regulatory intervention allows a service provider to earn unregulated profits for the duration of the regulation free period, compensating for the truncation of upside returns if its pipeline later becomes regulated.

The COAG Energy Market Review (EMR 2002) recommended the option of no price regulation for the first 15 years of operation should be available to all new transmission pipelines, provided the regulator is satisfied the pipeline:

- is a new transmission pipeline
- has sufficient vertical separation of ownership
- will publish tariffs for access to the pipeline
- will provide for all capacity to be fully tradeable.

Hence, the COAG Energy Market Review did not strictly recommend a regulation free period, but rather a form of light-handed regulation in which prices are unregulated for the first 15 years of a pipeline's operations (EMR 2002). To qualify for this approach, a pipeline would need to pass the abovementioned four tests applied by the regulator.

The COAG Energy Market Review did not elaborate on how the requirements for vertical separation and capacity trading would be met. However, recent experience with the Gas Access Regime suggests that they would need to be formalised in some way.

The concept of regulation free periods was also examined in the review of the national access regime (PC 2001c). The Commission recommended that COAG should consider mechanisms to facilitate efficient investment within the national access regime framework, including the possibility of fixed-term regulation free periods for contestable investments in essential infrastructure. Such investments were defined so as to include greenfield investments, as well as contestable augmentations to existing networks.

A number of inquiry participants supported regulation free periods as a method to facilitate investment in pipelines. For example, Envestra claimed:

> Regulation free periods (access holidays) would mitigate the risk of truncated returns and leave the market to develop in a commercially sustainable manner without distortions caused by regulation. (sub. 22, p. 39)

On the other hand, the Energy Markets Reform Forum, representing gas users, argued strongly against regulation free periods. It claimed:

> … an access holiday would allow an infrastructure owner free rein to extract monopoly rents through the period of the access holiday and would allow him an agreed real rate of return later on when the infrastructure came under the access regime. This would amount to a form of double dipping. (sub. 30, p. 32)

Further, the Energy Markets Reform Forum claimed that allowing unregulated rents would lead to:

> … the creation of excess burdens, discouraging investment downstream and upstream as well as potentially linking infrastructure facilities. (sub. 30, p. 32)

The key attraction of providing, *ex ante* and without case-by-case assessment, regulation free periods (for say 15 years) for *all* new (greenfield) pipelines is that it would directly and fully address the chilling effect the regulatory regime has on investment. The basic problem with this approach is there would be a risk that a pipeline would then be in a position to exert market power that inhibits upstream and downstream competition.

How long should a regulation free period be?

Support by inquiry participants for the introduction of a regulation free period was largely conditional on the details. One example is the length of a regulation free period. In its review of the national access regime, the Commission (PC 2001c) examined both fixed-term regulation free periods and approaches based on profitability criteria (net present value [NPV] approaches). The Commission noted that both approaches had limitations. It argued that while NPV-based regulation free periods were intuitively attractive, they would be informationally intensive and prone to gaming by service providers. Fixed term regulation free periods were judged to be more administratively simple, but at the expense of being an arbitrary length and uncertain in impact.

Some inquiry participants favoured an approach where pipelines remain exempt from regulation until certain prespecified profitability criteria are met. For example, AGL suggested the length of a regulation free period be determined on a case-by-case basis:

> AGL's preferred approach is to allow the performance of the project itself to determine the duration of the holiday [regulation free period] — the holiday would extend to the point when (if ever) the cumulative NPV of the project becomes positive. … In AGL's view, workable arrangements can be devised [for a NPV benefit sharing approach]. (sub. 32, p. 23)

Other inquiry participants favoured the administrative simplicity and certainty provided by a fixed-term regulation free period. APIA was one proponent of this view:

> APIA believes it is appropriate to specify a fixed period for an access holiday in advance rather than attempt to determine the optimal length of the access holiday on an individual pipeline basis. While the optimal duration for the price regulation free period may vary from pipeline to pipeline, any attempt to do so simply invites all of the intractable problems associated with any attempt to regulate greenfield investments. Therefore, it is likely to be more efficient to have a single period that applies to all pipelines. (sub. 44, pp. 91–2)

Duke Energy International supported fixed-term, rather than NPV-based, regulation free periods in order to limit regulator subjectivity:

> DEI [Duke Energy International] believes that it is better to specify a fixed period rather than determine the optimal length of the regulatory free period on a case-by-case basis. DEI believes if the latter approach were adopted, the regulator would have too much discretion in the process and determinations of the optimal regulatory free period length would be too subjective. This process of determining the optimal length of the regulatory free period could take a considerable amount of time, adding to uncertainty and possibly leading to project delays. (sub. 21, p. 34)

Gans and King (2004) noted that tailoring regulatory free periods to suit individual projects would be difficult in practice, but a 10 to 20 year period might be appropriate for high-risk projects:

> Optimal [access] holidays need to be judged on a case-by-case basis. This is likely to be difficult in practice. Rather, clear simple rules need to be established relating to the type of projects that are eligible for access holidays. The length of such holidays will be contentious. In our opinion, for relatively high risk projects with a 30 to 50 year lifespan, a 10 to 20 year holiday would seem appropriate. (Gans and King 2004, p. 100)

The COAG Energy Market Review (EMR 2002) recommended a 15-year fixed-term period of no price regulation for certain new transmission pipelines:

> The panel believes a 15 year regulation free period to be an appropriate balance between the competing objectives of providing greater certainty to pipeline companies and not excluding the possibility of regulation too far into the future should it prove to be warranted. (EMR 2002, p. 214)

However, many service providers claimed that 15 years would not be sufficient to facilitate investment, and that at least 20 years would be more suitable. Duke Energy International typified the arguments put forward by service providers:

> In DEI's [Duke Energy International's] experience, the period of time before a new gas pipeline reaches an acceptable rate of return is generally in the order of 20 to 25 years. On this basis, a regulatory free period of 15 years would be an absolute lower limit of acceptability from an investment point of view. DEI believes that the regulation free period should be extended to at least 20 years in order to minimise the potential of marginally profitable pipeline projects not proceeding due to any residual regulatory risk. (sub. 21, p. 34)

Which pipelines should be eligible for a regulation free period?

The COAG Energy Market Review (EMR 2002) recommended that new transmission pipelines should have the option of no price regulation for their first 15 years, provided they met certain tests applied by the regulator (such as vertical separation of ownership. The rationale for providing this option to all new transmission pipelines was as follows:

> Typically a proposed transmission pipeline is seeking to respond to a market demand. … the prospective initial users of the pipeline ('foundation users') have a significant degree of countervailing power — such that if a pipeline company seeks to charge excessive tariffs, they can approach another pipeline company to build the pipeline for them. As such, any transportation agreement reached between the pipeline company and users prior to the construction of the pipeline should be reasonable for both parties — so long as there are no control issues arising from vertical ownership. This means that in the short term at least, there is little or no scope for the benefit of imposing the burden of regulation upon the pipeline company. Indeed taking the costs into account,

the short-term impact of regulation in these circumstances is likely to be negative. (EMR 2002, p. 212)

The COAG Energy Market Review (EMR 2002) was not convinced that regulation free periods are suitable for distribution networks because there are difficulties in defining a greenfield distribution system (as opposed to the augmentation of an existing system) and there is less countervailing power in distribution.

In its review of the national access regime (PC 2001c), the Commission recommended that COAG consider the introduction of fixed-term regulation free periods for contestable investments. These were defined to include all greenfield investments as well as contestable augmentations to existing networks. The Australian Government's final response (Costello 2004) to the Commission's recommendation was that the matter would be considered in the context of industry-specific regimes, including this review of the Gas Access Regime.

Owners of distribution networks were in favour of having regulation free periods extended to distribution. For example, Envestra reasoned:

> Distribution pipelines connect consumers to transmission pipelines. Hence, the logic behind providing access holidays for transmission pipelines is also applicable to distribution networks. (sub. 22, p. 40)

Other service providers suggested that regulation free periods should be granted not only for greenfield investments but also for expansions and extensions of existing networks. For example, Epic Energy suggested:

> There should be no regulatory oversight in situations where the capacity being sold is new and tariffs are a product of market-based negotiations, not only for new pipelines but also for the expansion of existing pipelines. (sub. 37, p. 68)

APIA extended the argument, claiming that only granting regulation free periods to new pipelines has the potential to distort investment away from 'brownfield' expansions and extensions:

> As access holidays are only likely to apply to new pipelines, they may create a regulatory induced bias towards greenfield rather than brownfield investment. This in turn is likely to have the effect of increasing the overall cost of gas transport. This might occur where investors decide it is more appropriate, given the access holiday, to build a new pipeline instead of expanding an existing pipeline. (sub. 44, p. 93)

How should pipelines be treated after a regulation free period expires?

A further issue raised by inquiry participants was the treatment of pipelines after the expiration of a regulation free period. Many service providers argued that a pipeline should not be automatically covered at the end of the regulation free period, given that market circumstances might have changed considerably. For example, Duke Energy International claimed:

> … it would be inappropriate to apply mandatory coverage to a pipeline in 20 years time, when the regulatory framework and market conditions would be unknown. (sub. 21, p. 35)

Similarly, APIA favoured an approach where:

> … at the end of the 20 year [regulation free] period, the pipeline would remain unregulated until a bona fide access seeker lodged a successful coverage application … (sub. 44, p. 91)

The COAG Energy Market Review (EMR 2002) recommended that at the end of a pipeline's proposed 15 year period of no price regulation, an assessment would be made as to whether the pipeline was exerting market power. If the pipeline was found to be exerting market power, the COAG Energy Market Review recommended it should be deemed to be covered; otherwise, the pipeline should be uncovered.

The Commission's assessment

The Commission's recommendation to introduce binding no-coverage rulings would give regulation free periods of at least 15 years to new pipelines that do not meet the coverage criteria. Thus, the key issue is whether regulation free periods should also apply to new pipelines that satisfy the coverage criteria.

Regulation free periods might encourage investment in otherwise covered pipelines by at least partially addressing the truncation of returns during the initial years of such pipelines. Service providers would thus be able to achieve higher expected returns, in addition to lower regulatory risk, for the duration of the regulation free period.

However, the improvement in investment outcomes might be at the expense of competition in upstream and downstream markets. Pipelines that meet the coverage test would have been judged as having market power that would, in the absence of regulation, be likely to reduce efficiency. In chapter 4, the Commission concluded there is a case for having an access regime for such pipelines. Leaving such pipelines regulation free for a given period forgoes the efficiency benefits that have been assessed to be achievable through regulation. It is a second best solution that might allow prices to be inefficiently high for some period, so as to offset the truncation of upside returns once the pipeline is regulated. Furthermore, such an approach raises equity concerns, given that consumers today would potentially subsidise investments to provide for cheaper consumption by future consumers after the expiration of the regulation free period.

The Australian Gas Association (sub. 13, p. 59) noted that contestability in the construction phase and the strong commercial incentives to maximise throughput mean that greenfield investments require special mechanisms, such as regulation free periods. Further, some inquiry participants noted that greenfield pipelines are constrained in their pricing in their initial years as they attempt to gain market penetration. For example, the ACCC said:

> … it is expected that a 15-year economic regulation free period would allow a pipeline company the freedom to set tariffs at a rate that would enable it to earn potential blue sky returns in order to offset *ex ante* probabilities of black sky scenarios. However, a new pipeline may not have the ability to achieve higher returns in the early stages of the project as envisaged by the economic regulation free period. (sub. 48, p. 65)

Under the Commission's recommended coverage test (chapter 6) and binding no-coverage rulings, pipelines without market power would qualify for a regulation free period of at least 15 years. As noted above, the COAG Energy Market Review (EMR 2002) claimed that few, if any, new transmission pipelines would have market power. In contrast, it observed that this might not hold to the same extent for distribution systems. If this assessment is accurate, then most, if not all, new transmission pipelines would qualify for a 15-year regulation free period under the Commission's proposal for binding no-coverage rulings. The outcome for distribution is less certain.

The availability of a light-handed monitoring option, as recommended in chapter 8, is also likely to reduce the need for regulation free periods. The inclusion of the monitoring alternative effectively sets the threshold for access arrangements with reference tariffs higher than currently, with fewer pipelines subject to such regulation.

Under the Commission's proposed revised Gas Access Regime, there would be far less scope for asymmetric truncation, due to the availability of a light-handed monitoring option. The argument for a mechanism to address truncation relates to only those pipelines that would be subject to an access arrangement with reference tariffs.

An additional concern about the introduction of regulation free periods for greenfield projects is the potential for it to distort investment patterns because of the asymmetric regulatory treatment of existing and new pipelines. A regulation free period offered exclusively to greenfield investments creates an incentive for investors to undertake greenfield investments even when it might be more efficient to expand or augment their existing infrastructure. The Commission's recommendation to introduce binding no-coverage rulings would ensure that regulation free periods are only granted to pipelines with limited market power.

In summary, the Commission considers that regulation free periods have the potential to at least partially remedy asymmetric truncation. However, introducing such an approach nondiscriminately has the potential to impose costs in cases where the service provider has market power and is able to limit upstream and downstream competition for the duration of the regulation free period.

FINDING 9.8

The Commission's recommendation to introduce binding no-coverage rulings would give regulation free periods of at least 15 years to new pipelines that do not satisfy the coverage criteria. Extending the application of regulation free periods to new pipelines that satisfy the coverage criteria could reduce competition in upstream and downstream markets, and possibly distort investment. The case for providing regulation free periods to all new pipelines is weakened further by the Commission's recommendation to have a monitoring option as an alternative to a regulated access arrangement with reference tariffs.

Extended duration access arrangements and fixed principles

As mentioned in section 9.2, extended duration access arrangements and fixed principles are possible under the current Gas Code. Such mechanisms reduce regulatory risk to some extent. The ACCC (2002a) draft greenfields guideline suggests that such mechanisms might also be used to address the truncation problem. By reducing the frequency or scope of regulatory resets, these mechanisms increase the period in which a service provider can achieve blue sky returns.

As noted in section 9.2, if an access arrangement will last for longer than five years, then the regulator has to consider mechanisms to address the risk of inaccurate forecasts. The regulator is afforded considerable discretion in approving these trigger mechanisms.

In the Commission's view, extended duration access arrangements and fixed principles have the potential to reduce the investment distorting effect of asymmetric truncation (and could possibly eliminate it in the unlikely event that the access arrangement is for the life of the project and does not include a benefit sharing mechanism). However, the benefits of such an approach might be offset by regulators setting strict trigger mechanisms for a review of the access arrangement (such that it effectively defaults to a five year arrangement). In the case of fixed principles, benefits could be offset by regulators changing other parameters to appropriate any blue sky returns being earned by the service provider. Regulators also have scope to offset the benefits by compensating for the extended period between regulatory resets by setting the terms of regulation more harshly after observing an extended period of blue sky returns.

9.4 Summing up

In chapter 6, the Commission recommended maintaining the current regulatory approach — access arrangements with reference tariffs — for cases where it would be warranted. However, a disadvantage of the current Gas Access Regime is that it can distort investment due to regulatory risk and the asymmetric truncation of returns.

Measures to reduce regulatory risk

The types of regulatory risk encountered by investors under the current regime include:

- *coverage risk* — uncertainty about whether a pipeline will be covered
- *parameter risk* — uncertainty about the regulatory parameters that will be applied if a pipeline is covered.

To reduce coverage risk, the Commission has recommended changing the Gas Access Regime so the relevant Minister can issue binding no-coverage rulings before a pipeline is constructed.

The existing Gas Code already includes some mechanisms to limit parameter risk, but their application is subject to the wide discretion given to regulators. Hence, considerable uncertainty remains about how parameter risk can be reduced, if at all, under the existing Gas Code. To a large extent, this reflects a tension, when prescribing reference tariffs, between providing very specific rules and having sufficient flexibility to accommodate the unique circumstances of each pipeline.

Measures to address asymmetric truncation

The asymmetric truncation of (upside) returns is difficult to address if regulation is to involve regulator-approved access arrangements with reference tariffs. Measures already possible under the Gas Code — such as symmetric truncation, service provider initiated reviews, extended duration access arrangements, and fixed principles — are not very effective ways of addressing the truncation problem.

The possibility of introducing a fixed truncation premium was raised in the review of the national access regime (PC 2001c). The Commission has now concluded that truncation premiums are a less than ideal solution to the problem of asymmetric truncation, given the difficult implementation issues involved. This includes how to determine the level of a truncation premium (a potential source of regulatory error) and whether truncation premiums should be restricted to riskier greenfield projects.

It should also be noted that the Commission's recommendation to introduce binding no-coverage rulings would give regulation free periods of at least 15 years to new pipelines with limited market power. For other new pipelines, the Commission's recommended revised Gas Access Regime would reduce the likelihood of asymmetric truncation, due to the availability of a monitoring option.

10 Ring fencing and associate contracts

The purpose of this chapter is to examine the ring fencing and associate contract provisions of the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime). The ring fencing provisions require the separation of the transmission and distribution operations of a vertically integrated utility from the other operations (such as production and retail businesses). Section 4 of the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) outlines the minimum ring fencing obligations of service providers (box 10.1). The associate contract provisions prevent a ring fenced service provider from entering into a contract with an affiliated business (associate) without obtaining the approval of the relevant regulator (box 10.2). Section 7 of the Gas Code outlines the process to gain approval for an associate contract.

Box 10.1 **Minimum ring fencing obligations under the Gas Code**

Broadly, s.4.1 of the Gas Code requires a service provider to:

- be a legal entity — s.4.1(a)
- not carry on a related business (essentially a business of producing, purchasing or selling natural gas) — s.4.1(b)
- establish and maintain separate accounts for the activity that is the subject of each access arrangement — s.4.1(c)
- establish and maintain a consolidated set of accounts for all the activities undertaken by the service provider — s.4.1(d)
- allocate costs shared between different accounts in a fair and reasonable manner — s.4.1(e)
- ensure that confidential information is not disclosed to any other person without the permission of the person to whom the information pertains — ss4.1(f) and (g)
- ensure that marketing staff do not work for both the service provider and an associate taking part in a related business — ss4.1(h) and (i).

The Gas Code provides scope for the regulator to impose additional ring fencing obligations on service providers. It also contains provisions to waive some of the minimum ring fencing obligations.

Source: Gas Code.

Box 10.2 **What is an associate and an associate contract?**

An associate is defined under the Gas Code with reference to certain sections of corporations law (*Corporations Act 2001*):

> … [associate] has the meaning it would have under division 2 of part 1.2 of the Corporations Law [*Corporations Act 2001*] if ss13, 14, 16(2) and 17 of that law were repealed, except that a person will not be considered to be an associate of a service provider solely because that person proposes to enter, or has entered, into a contract, arrangement or understanding with the service provider for the provision of a service. (s.10.8)

Under these sections, associates are defined in terms of their relationship to a body corporate. The following are defined as associates:

- a director or secretary of the body corporate
- a related body corporate
- a director or secretary of a related body corporate
- a holding company of the body corporate
- a subsidiary of the body corporate
- a subsidiary of a related body corporate
- a subsidiary of a holding company of the body corporate (IPART 2001, p. 3).

The Gas Code defines an associate contract as:

> (a) a contract, arrangement or understanding between the Service Provider and an Associate in connection with the provision of a Service; or
>
> (b) a contract, arrangement or understanding between the Service Provider and any person in connection with the provision of a Service which provides a direct or indirect benefit to an Associate and which is not an arm's length transaction. (s.10.8)

Source: Gas Code; IPART 2001.

The rationale for the ring fencing provisions is to maintain the integrity of the regulatory framework under the Gas Code. A nonseparated vertically integrated utility owner would have an incentive to use its market power (in the monopoly part of its business) to limit competition in the potentially contestable elements (retail and production). The Hilmer Committee (1993) strongly advocated structural separation as a way of facilitating competition in upstream and downstream markets.

The associate contract requirements are designed to maintain the integrity of the ring fencing provisions. Regulatory oversight of contracts between a ring fenced service provider and affiliated business is intended to ensure that the service provider does not use contractual mechanisms to favour these affiliated businesses. The ring fencing and associate contract provisions are particularly important in circumstances where a company is involved in all sectors of the gas supply chain (production, transmission, distribution and retail).

10.1 Purpose and effectiveness of ring fencing and associate contract provisions

Purpose of the ring fencing provisions

The ring fencing provisions in the Gas Access Regime are designed to prevent vertically integrated utility owners from pursuing actions to limit competition in upstream or downstream markets. A vertically integrated utility owner might limit competition in these potentially contestable markets by:

- denying potential upstream and downstream competitors access to the essential facility
- charging potential upstream or downstream competitors a high price
- using commercially sensitive information gained from its involvement in upstream and downstream markets to gain a favourable position in access negotiations with potential upstream and downstream competitors
- allocating an unreasonable proportion of its total costs to regulated elements of the business to justify charging users a higher tariff.

A vertically integrated utility owner has an incentive to pursue these behaviours to increase its total profits. The ring fencing provisions are designed to reduce the incentives and opportunities for the utility owner to engage in each of these potentially anticompetitive behaviours by making its behaviour more transparent and making the task of applying access regulation more transparent and efficient. The efficacy of the ring fencing provisions might be eroded by corporate relationships inhibiting independent commercial decision making (for example, cross-membership of boards).

The ring fencing provisions are in s.4 of the Gas Code. Sections 4.1(a) and (b) of the Gas Code state that the service provider of a covered pipeline must be a legal entity registered under corporations law and must not carry on a related business (the production, purchase or retailing of gas). One way for a vertically integrated utility owner to comply with these provisions is to form a parent company that owns two separate entities:

- a subsidiary in an upstream or downstream market
- a regulated pipeline or network service provider.

This vertical separation is designed to reduce the ability of the service provider to leverage its market power into upstream and downstream markets. Under corporations law, directors of each affiliate business have a responsibility to look after the interests of shareholders of their business. This should reduce directors' incentives to favour affiliate (associate) businesses.

Further, ss4.1(f)–(i) of the Gas Code restrict the disclosure of confidential information and the movement of marketing staff between the vertically separated businesses, to ensure commercially sensitive information is not used to improve the competitive position of the entity in the upstream or downstream market.

However, there is still the potential tension between the ring fencing provisions and corporations law under which the board of a parent company has an obligation to maximise the total value of the parent company. Where a parent company has subsidiaries operating in both the regulated and unregulated part of the gas market, an incentive exists to allocate a greater proportion of costs than is reasonable to the regulated subsidiary. Allocating costs in this manner could lead to higher regulated tariffs, adversely affecting upstream and downstream businesses, but increasing the overall profits of the parent company. To overcome this incentive, ss4.1(c)–(e) of the Gas Code require a service provider to:

- maintain separate accounts for the services provided by each of its covered pipelines
- maintain consolidated accounts for its entire business (which might include ownership and operation of several pipelines or networks)
- allocate according to certain principles, any costs shared between services provided by each covered pipeline, with any other activity (such as activities undertaken by an affiliated retailer or on an uncovered pipeline).

Purpose of the associate contract provisions

The associate contract provisions are designed to maintain the integrity of the ring fencing provisions. Even with ring fencing provisions in place, the parent company could still seek to use, or influence, its regulated service provider so that it favours an associate (businesses in an upstream or downstream market that are also owned by the parent company). The associate contract provisions under s.7 of the Gas Code are designed to prevent the service provider treating its associates more favourably, by requiring the relevant regulator to approve contracts between these parties.

The relevant regulator must not refuse to approve an associate contract unless it considers that the proposed contract would have the effect, or be likely to have the effect, of ‘substantially lessening, preventing or hindering competition in a market’ (Gas Code, s.7.1). Public consultation is required if the contract is for supply at a price other than the reference tariff.

Are the ring fencing and associate contract provisions effective?

A number of inquiry participants noted the importance of the ring fencing and associate contract provisions to the Gas Access Regime. The Australian Gas Association (AGA) commented:

> Regulated gas businesses accept the need for appropriate regulatory oversight in regards to associate contracts and agreed as part of the broader gas reform process to these provisions applying to their operations. In association with the ring fencing provisions of the national Gas Code (contained in part 4 of the Code) this oversight recognises that network owners must deal at ‘arms length’ with downstream market participants.
>
> The need for these arrangements is particularly clear where, as was the case at the outset of gas market reform, vertically integrated gas businesses both owned gas infrastructure and retailed gas transported through the infrastructure. (sub. 13, p. 84)

The Australian Pipeline Industry Association (APIA) also acknowledged:

> … credible ring fencing requirements form a legitimate component of the Gas Access Regime and provide access seekers with the confidence that their commercial position will not be undermined. (sub. 44, p. 81)

Similarly, Duke Energy International commented:

> … ring fencing requirements are an integral part of any regulatory regime that seeks to provide access and encourage competition in upstream and downstream markets. The separation of vertically integrated gas business has been the necessary first step in the reform of the gas industry in Australia over the last decade. In situations where gas transmission pipelines are also involved in a related upstream or downstream business, ring fencing ensures that these businesses do not receive favourable treatment, thereby hindering the ability of other firms to compete. (sub. 21, p. 27)

In addition, some participants considered that the current provisions had been broadly effective. The AGA noted:

> The existing provisions of the national Gas Code relating to ring fencing have been broadly effective and have been used as a model for ring fencing arrangements in other sectors (including the electricity sector). (sub. 13, p. 94)

A number of inquiry participants argued that the ring fencing provisions have been effective because they are consistent with the commercial interests of the parent company in many instances. The Australian Petroleum Production and Exploration Association stated that adopting ring fencing provisions might provide ‘an advantage for the contestable elements of that business' (trans., p. 361). ExxonMobil supported this view:

> If you look at a company that is involved in both distribution and as a retailer and pipeline owner, by separating out that pipeline and running that as a commercially separate entity and fully utilising the capacity that they have in that pipeline — is in their commercial interest. (trans., p. 241)

Further, the AGA noted:

> … competitive pipelines operating outside of the gas access regime have adopted similar ring fencing arrangements to provide market participants with confidence of the appropriate separation of regulated and nonregulated activities. (sub. 13, p. 94)

However, other inquiry participants argued that the ring fencing and associate contract provisions have not been effective because regulators are not enforcing the provisions strongly enough. Orica argued that it is very difficult in New South Wales to be sure the service provider is fulfilling the required ring fencing and associate contract requirements. It alleged:

> … AGL [Australian Gas Light Company] Gas Networks Limited entered into associate contracts involving very substantial amounts of gas, without the approval of the regulator. The matters only became public after the regulator completed the 2000 access review. Potential gas suppliers have publicly assessed that retail competition was foreclosed arising from that episode. (sub. 28, p. 9)

The Energy Action Group lacks confidence in the enforcement of the ring fencing provisions, given the 'almost blind acceptance of any material submitted by the regulated entity' (sub. 27, p. 7). BHP Billiton raised a similar concern:

> … [its] concern with the operation of the [Gas] 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. (sub. 26, p. 106)

There are penalties under the Gas Access Regime for breaches of the ring fencing and associate contract provisions (table 10.1). Civil penalties apply to breaches of regulatory and conduct provisions and any person can seek an injunction, declaratory relief and damages for breaches of conduct provisions (schedule 1 ss34–37 of the *Gas Pipelines Access Act*).

However, BHP Billiton questioned the effectiveness of these penalty provisions:

> 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 … 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. (sub. 26, p. 107)

Table 10.1 **Penalties for breaches of ring fencing and associate contract provisions**

Sections	*Type of provision*	*Maximum civil penalty (Western Australia)*	*Maximum civil penalty (other jurisdictions)*[a]
		$	*$*
4.1(a), (b), (c), (d), (e), (h) and (i)	Regulatory	100 000 and 10 000 daily[b]	100 000
4.1(f) and (g)	Conduct	100 000	100 000
4.2	Regulatory	None specified	None specified
4.3	Regulatory	100 000 and 10 000 daily[b]	100 000
4.12	Regulatory	None specified	None specified
4.13	Regulatory	None specified	None specified
4.14	Regulatory	50 000	50 000
7.1	Conduct	100 000	100 000

[a] All jurisdictions (other than Western Australia) apply the South Australian Regulations. [b] There is scope for a fixed fine ($100 000) and a daily fine ($10 000) for each day the breach continues.

Sources: Gas Pipelines Access (South Australia) Regulations 1999; Gas Pipelines Access (Western Australia) Regulations 2000; Gas Code, s.10.7.

Some of the problems associated with enforcement of the ring fencing provisions might be overcome by the move towards a national energy regulator. BHP Billiton argued:

> … 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 contribute to inconsistencies in both regulatory outcomes, as well as the propensity or vigour with which the [Gas] Code is applied … [there are] 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. (sub. 26, pp. 123–24)

Other inquiry participants were unconvinced that the ring fencing and associate contract provisions could ever eliminate the incentives for affiliated businesses to act in the interests of the parent company. Enertrade claimed that ring fencing provisions are not effective because ‘ultimately ring fencing occurs at an operational level but does not occur at the senior management level’ (trans., p. 292).

Enertrade argued that making details of affiliate transactions transparent is a preferable way of preventing the service provider from treating its affiliate businesses more favourably:

> … the better way to respond to those [affiliate relationships] is to have the affiliate transaction fully transparent, fully postable and auditable in terms of the information upon which the transaction was done. But that's where you get the openness in behaviour. (trans., p. 293)

Duke Energy International (sub. 21, p. 28) and APIA (sub. 44, p. 82) noted that competitive concerns related to contracts between associates could be overcome by requiring service providers to offer access to external parties on the same terms and conditions offered to its associates.

However, there might be limitations in removing the regulatory oversight of associate contracts and relying on transparency of affiliate transactions and nondiscriminatory terms and conditions. Such an approach would have confidentiality concerns. Under the current associate contract provisions, confidentiality concerns are addressed by s.7.3 of the Gas Code. This section requires a regulator not to make public any part of a contract that a service provider claims is confidential (except where a regulator is of the opinion the disclosure would not harm the business interests of a service provider or user). Even if a regulator does not make the information public, it can still consider the confidential information in making its decision. Under the transparency of affiliate transactions approach, there would be no scope to keep information confidential because transparency would effectively replace regulatory oversight. Mandating the release of commercially sensitive information has the potential to disadvantage service providers and their affiliates by making their business strategies apparent to their competitors.

Further, it is unlikely that the transparency of affiliate transactions alone would be sufficient incentive for a service provider not to favour its affiliates. The model suggested by Duke Energy International and APIA — whereby the service provider would be required to offer external parties the same terms and conditions offered to affiliates — could overcome this problem.

The Commission notes the inquiry participants' broad acknowledgement of the rationale for ring fencing and associate contract provisions within the regulatory framework. In general, participants argued that the provisions are effective, particularly when compliance with the provisions is in the commercial interests of the service provider. The Commission considers the only alternative proposed — making affiliate relationships transparent and offering nondiscriminatory pricing — has limitations (in terms of confidentiality concerns) relative to relying on the existing provisions in the Gas Code.

FINDING 10.1

The ring fencing and associate contract provisions of the Gas Code are warranted and are important for an effective regulatory regime.

10.2 Costs imposed by the ring fencing and associate contract provisions

While the ring fencing and associate contract provisions are warranted, they can impose costs on a service provider and its affiliate businesses. This section examines the nature of these costs and considers whether improvements to these provisions are possible to make them less costly.

Ring fencing provisions

The ring fencing provisions of the Gas Code have the potential to impose costs on a service provider and its affiliated businesses. In developing the Gas Code, the Gas Reform Taskforce suggested:

> From the perspective of the service provider, the ring fencing requirements have the potential to be one of the most intrusive, disruptive and costly provisions of the [Gas] Code. Ring fencing will mean major cultural changes for many organisations. (Gas Reform Task Force 1996, p. 73)

However, in general, service providers have not argued that the ring fencing provisions are proving onerous.

Service providers and affiliated businesses might bear two types of costs in complying with the ring fencing provisions:

- the commercial costs that arise from separating the transportation elements of the business from their other business activities
- the administration costs of complying with the provisions.

Where these costs are large relative to the benefits, s.4.15 of the Gas Code provides the regulator with discretion to waive some of the minimum obligations. However, the regulator also has the discretion to impose additional ring fencing obligations on the service provider (s.4.3).

Commercial costs

Separating the business activities of a vertically integrated business might impose costs on a service provider and its affiliate, arising from:

- the duplication of functions across the separated businesses
- the higher transaction costs of administering contracts and contract enforcement between affiliate businesses.

Some of the minimum ring fencing provisions require duplication of functions across the vertically separated business. Sections 4.1(h) and (i) of the Gas Code prevent the marketing staff of a service provider from working for an associate that operates a related business. This requirement might involve the hiring of more staff than would be needed under integration. In its November 2000 application to the Queensland Competition Authority (QCA) to waive its obligations under ss4.1(h) and (i) of the Gas Code, Allgas Energy argued that under the obligations it would need to employ an extra person, creating unnecessary costs (table 10.2).

Table 10.2 **Decisions regarding waiving the minimum ring fencing requirements**

Proposed waiver/waivers	*Regulator*	*Decision date*	*Decision*
Run a related business by Santos, Origin Energy Resources (Origin Energy) and Delhi Petroleum	ACCC	May 2002	Waiver granted
Share staff involved in marketing by NT Gas	ACCC	March 2002	Waiver granted
Share staff involved in marketing by Allgas Energy	QCA	March 2001	Not approved
Run a related business and share staff involved in marketing by Origin Energy	Office of Gas Access Regulation	November 2000	Conditional waivers granted
Share staff involved in marketing by Great Southern Energy Gas Networks	Independent Pricing and Regulatory Tribunal	November 1999	Not approved

Source: Code Registrar website.

The Commission considers it unlikely that the commercial costs of complying with ss4.1(h) and (i) of the Gas Code would be large. For larger businesses, compliance might only require the division of marketing resources between a service provider and its affiliate. For smaller businesses, where a single person has carried out certain functions, the separation of business activities might create some duplication of roles. However, given that regulators have demonstrated a willingness to waive these obligations in some cases, the costs are unlikely to be unnecessarily large.

In addition, the AGA indicated that the ring fencing provisions have not had an adverse impact on investment, noting that it:

> … does not consider that ring fencing arrangements have had a detrimental impact on investment, and, to date, compliance costs for ring fencing arrangements in most jurisdictions have not been outweighed by the benefits to the community arising from such arrangements. (sub. 13, p. 94)

Further, Envestra claimed that ‘a light-handed application of the ring fencing provisions in s.4 of the [Gas] Code would not unduly affect the incentive to invest’ (sub. 22, p. 41).

Administrative costs of compliance

The administrative costs of complying with ring fencing requirements of the Gas Code depend on the extent to which the relevant regulator requires the service provider to demonstrate that it meets the requirements. A number of inquiry participants raised concerns about the costs of demonstrating compliance with the ring fencing accounting requirements of s.4.2 of the Gas Code. This section states that a service provider, to comply with ss4.1(c)–(e), must comply with any general accounting guidelines published by the relevant regulator. However, the QCA is the only regulator that has issued such guidelines. The Australian Competition and Consumer Commission (ACCC) has recently issued draft accounting guidelines.

In commenting on the general accounting guidelines for gas distribution network service providers, published by the QCA in 2003, Allgas Energy noted:

> These are the first guidelines to have been published by a regulator and require extensive accounting templates to be completed, including working papers for each specific cost allocation, as well as a cost allocation manual to be submitted and approved by the regulator. There is also an audit undertaken of the regulated accounts by an independent auditor. (sub. 25, p. 15)

Both of the Queensland distribution businesses (Allgas Energy and Envestra) argued that the QCA accounting guidelines impose large administrative compliance costs. Envestra claimed:

> The Queensland regulator has … imposed guidelines that, in Envestra’s view, go beyond that necessary to implement ring fencing arrangements. These guidelines require the collection of a significant amount of detailed information and additional obligations on the service providers (for example, a director’s responsibility statement) that are not necessary … The accounting guidelines only serve to increase the cost of gas to consumers in an already competitive market. (sub. 22, pp. 40–1)

Allgas Energy stated:

> Clearly, the provisions in s.4 of the Gas Code need to be clarified to ensure that they are not onerous in their application. (sub. 25, p. 15)

APIA used the QCA accounting guidelines as an example to express its more general concern that in addressing the cost allocation requirement:

> … regulators have added unnecessary complexity and interference in the commercial operations of pipeline businesses through requiring the adoption of a regulator approved or published accounting guidelines as provided for in s.4.2 … Through these guidelines, regulators are able to prescribe a method of collection and allocation of shared costs in an arbitrary manner which need not correlate with the way the business is operated and is not the way the service provider would allocate costs in an access arrangement. APIA believes it is inappropriate for ring fencing to be used to prescribe cost allocation methodologies applicable to the regulated business. In other words, APIA believes that cost allocation for ring fencing should be confined to the allocation of costs between regulated and unregulated affiliated businesses, rather than the internal cost allocation by an access provider (that is, within the regulated business alone). (sub. 44, pp. 81–2)

Without general accounting guidelines published by the regulator, a service provider is required by s.4.2 of the Gas Code to comply with its own guidelines (as approved by the regulator). Gas users argued that allowing a service provider to develop its own guidelines does not provide sufficient regulatory oversight to prevent the transfer of costs between regulated and unregulated affiliate businesses. Users offered support to regulators to develop accounting guidelines. The Energy Action Group recommended:

> … that the national regulators forum [Utility Regulators Forum] needs to develop a clear, precise, transparent and verifiable set of regulatory accounting and benchmark standards that minimise the level of utility gaming or the perception of gaming. (sub. 27, p. 7)

The Economic Regulation Authority (which has assumed the responsibilities of the former Office of Gas Access Regulation) noted that there are ‘initiatives underway’ in the Utility Regulators Forum to settle on appropriate standardised information requirements (sub. DR116, p. 9).

The Commission considers that s.4.2(a) of the Gas Code has the potential to impose administrative compliance costs on service providers, particularly when the information required is inconsistent with the accounting practices of, or information collected by, the service provider.

In the draft report for this inquiry, the Commission proposed that the Gas Code be amended to standardise the information requirements and guidelines across jurisdictions and to ensure they are as close as possible to existing gas industry accounting or record keeping practices. The Commission's intent in making this proposal was that the administrative compliance costs on service providers be reduced, particularly those of service providers that operate covered pipelines or networks in a number of jurisdictions.

Participants' responses to this proposal were mixed. Some were supportive of the proposal (or at least parts of it). ExxonMobil, for example, agreed:

> … that information requirements be standardised as close to existing gas industry accounting or record keeping practices as possible. (sub. DR78, p. 6)

In addition, WMC Resources argued:

> … [it could see] no reason why the requirements for establishing and maintaining information should not be uniform across all jurisdictions. (sub. DR99, p. 23)

In contrast, other participants were concerned with the implementation of the Commission's proposal. The Australian Gas Light Company (AGL), for example, considered that it:

> … may in fact result in more intrusion and more complexity as it may require regulated businesses to change their current business practices to meet new requirements and result in increased costs. (sub. DR84, p. 22)

Similarly, the Energy Networks Association (ENA, which has replaced the AGA) noted:

> … our concern would be if regulatory authorities themselves worked hard for the process of harmonising information requirements then a maximum of information collection approach would be adopted rather than a minimum approach … (trans., p. 596)

In addition, the ACCC argued that it was beneficial to have flexibility in the information requirements:

> … flexibility in the type of information that can be collected is important to recognise differences between regions and circumstances of individual pipelines, as well as to recognise that relevant benchmarks may evolve over time. For example, the benchmarks relevant to a greenfields transmission pipeline may differ from those of an established transmission pipeline. (sub. DR101, p. 55)

The ENA claimed that there was disagreement between regulators regarding their information collection powers under the Gas Access Regime and that as a result it considered:

> … [the] standardisation of information gathering requirements … is unlikely to be progressed and should be deferred pending regulatory bodies determining the types of information they require for the monitoring of compliance with the [Gas] Code and which they currently cannot collect. (sub. DR85, p. 22)

The ENA also noted that the issue of standardising information requirements should be 'a matter considered in consultation with industry in the context of moves to establish a national energy regulator' (sub. DR85, p. 22).

The Commission acknowledges that the establishment of a national regulator for both gas transmission and distribution in all States and Territories (except Western Australia) is likely to progress the standardisation of information requirements across jurisdictions. In addition, a national regulator (given its wider application) might be better able to ensure that its accounting guidelines are as close to existing gas industry practices as possible, but also flexible enough to apply to individual pipelines or networks.

Regulatory discretion in applying ring fencing provisions

Regulators have used some of their discretionary powers in waiving the minimum ring fencing obligations under the Gas Code (s.4.15). These waivers can be granted if the regulator is satisfied that the costs to the service provider from complying with the provisions outweigh any public benefit that would arise from compliance. Generally, these waivers have been granted for the requirement that marketing staff cannot work for a related business. In one case, a service provider was granted a waiver from the requirement that it not conduct a related business (table 10.2).

The AGA noted that regulatory authorities have waived ring fencing obligations in some circumstances:

> … the AGA notes that in a number of cases regulatory authorities have agreed to waive some minimum ring fencing obligations (for example, in relation to marketing staff) in recognition of the need in some smaller markets to work cooperatively to build gas markets. (sub. 13, p. 94)

By waiving the minimum ring fencing requirements in a number of cases, regulators have demonstrated the flexibility provided by s.4.15 of the Gas Code to waive provisions where the costs exceed the benefits.

There is a cost associated with applications to waive obligations (particularly the process of public consultation). However, regulators' power to reject applications made on trivial or vexatious grounds, means that these costs are unlikely to outweigh the benefits to small service providers from the possible waiver of unnecessarily costly obligations.

Regulators have not used their discretionary power under s.4.3 of the Gas Code to impose additional ring fencing obligations on service providers.

Associate contract provisions

The associate contract provisions in the Gas Code have the potential to impose costs on service providers. The associate contract decisions since the introduction of the Gas Code are summarised in table 10.3.

Service providers might incur two types of costs in complying with the associate contract provisions:

- the commercial costs of having to get contracts with associates approved by the regulator
- the administrative costs of complying with the provisions.

Commercial costs

The requirement that affiliate businesses submit contracts to the regulator for approval might impose costs on the service provider and its affiliate, arising from:

- inhibiting their ability to respond promptly to commercial opportunities
- publicly releasing commercially sensitive information as part of the approval process.

Inhibiting prompt responses to commercial opportunities

Section 7.4 of the Gas Code states that a regulator is deemed to have approved an associate contract if it does not approve the contract within 21 days after receiving the application (or 49 days when the regulator is required to conduct a public consultation). If the regulator seeks additional information from the service provider, then the time limit is extended by the time taken by the service provider to respond to the request. AGL provided an example of the delays (and administrative costs) associated with approval of associate contracts:

> … the approval process began in November 2002. The contract related to one customer who will consume less than 10 TJ per annum and pay annual transportation costs of less than $50 000. AGLGN [AGL Gas Networks] was prevented from meeting the needs of this customer until the approval process finished in March 2003, two months after the date for which the customer originally requested gas supply and involved a cost to AGLGN of approximately $25 000. (sub. 32, p. 29)

Table 10.3 **Associate contract decisions, September 1998 to June 2004**[a]

Regulator/Proposed associate contract(s)	*Decision date*	*Decision*
Australian Competition and Consumer Commission		
Eastern Australian Pipeline Limited (EAPL) and AGL Wholesale Gas (AGLWG): Moomba–Culcairn	30 September 1998	Approved
EAPL and AGLWG: Moomba–Culcairn	2 December 1998	Approved
EAPL and AGLWG: Moomba to eight delivery points	19 April 1999	Approved
EAPL and AGLWG: Moomba–Henty	19 August 1999	Approved
EAPL and AGLWG	10 February 2000	Approved
EAPL and AGLWG	3 March 2000	Approved
EAPL and AGLWG: Moomba–Bulla Park Pump Station	9 March 2000	Approved
EAPL and AGLWG: Moomba–Wilton and Moomba–Canberra	1 June 2000	Approved
Independent Pricing and Regulatory Tribunal		
AGL Gas Networks (AGLGN) and AGL Energy Sales and Marketing (AGL ES&M) and AGL Wholesale Energy	13 November 1998	Approved
AGLGN and AGL Retail	9 February 2000	Approved
Great Southern Energy Networks (GSEGN) and Country Energy	28 November 2001	Approved
AGLGN and AGL ES&M: variations to standard transportation agreement	12 December 2001	Variations approved
AGLGN and AGL ES&M: variations to standard transportation agreement	19 December 2001	Variations approved
AGLGN and AGL ES&M: variations to standard transportation agreement	23 January 2002	Variations approved
GSEGN and Country Energy	20 February 2002	Approved
AGLGN and AGL ES&M: variation to trunk transportation services	8 May 2002	Variations approved
AGLGN and AGL Retail: variation to tariff transportation service	19 February 2003	Variations approved
AGLGN and AGL Retail	29 October 2003	Approved
AGLGN and AGL ES&M	29 October 2003	Approved
AGLGN and ActewAGL Retail: to supply small end users	29 October 2003	Approved
AGLGN and ActewAGL Retail: to supply large end users	29 October 2003	Approved
AGLGN and AGL ES&M	11 February 2004	Approved
Office of Gas Access Regulation		
AlintaGas Networks and AlintaGas Sales	18 April 2001	Approved
AlintaGas Networks and AlintaGas Sales	30 April 2002	Approved
Queensland Competition Authority		
Allgas Energy/Allgas Toowoomba and ENERGEX Retail	21 November 2002	Approved

[a] Information available from Code Registrar's website at 9 June 2004.

Source: Code Registrar's website.

A number of participants argued that the requirement to have the contracts between a service provider and its affiliates approved (and the delays this created), placed an affiliated retailer at a competitive disadvantage to other retailers:

An issue of competitive neutrality of regulation also arises, as new entrant retail businesses without an associated network business may be more able to quickly respond with potential contractual offerings as they would not need to seek their approval by any regulatory body. This has the potential to result in economically inefficient market outcomes. (AGA, sub. 13, p. 86)

… AGL considers that the current associate contract approval requirements in the Gas Code have resulted in a significant waste of resources, has placed its related retailer at a competitive disadvantage and, most importantly, has inconvenienced end users. (AGL, sub. 32, p. 29)

… the s.7.1 requirement [of the Gas Code] for regulator approval of associate contracts is an unnecessary requirement which has the potential to significantly disadvantage affiliates due to the potential time delay in getting such approval. (APIA, sub. 44, p. 82)

The AGA also claimed that the associate contract provisions created delays that reduced the service provider's ability to respond in a timely manner to potential load growth opportunities:

… a requirement for distribution businesses to submit commercially sensitive agreements for approval to the regulatory authority before they are entered into constrains the ability of a service provider with associated but ring fenced retail businesses to respond in a timely manner to potential load growth available as potential throughput to the distribution business.

For example, if a contract for the sale of gas relating to a new potential large contestable customer must be presented by the distribution business and the associated ring fenced retail business to the regulatory authority, then substantial delays are possible. These delays could result in the failure of the regulated service provider to grow the gas network throughput in a timely manner. (sub. 13, p. 86)

Further, some participants claimed that the requirement to gain approval of certain associate contracts imposed these costs with little apparent benefits. In particular, AGL argued that regulatory approval is not required:

- For associate contracts for reference services.
- Where an associate retailer requests a negotiated service to a customer site and the service provider informs the customer of the offer made to the retailer and advises the customer that the customer can accept the offer directly or through any retailer. (sub, 32, p. 29)

The Commission is not convinced that the regulatory approval of associate contracts for particular negotiated services (as described by AGL) is not required. While customers are given the option of choosing another retailer, this does not necessarily mean the service provider and associate (retailer) cannot engage in behaviour that substantially lessens competition. A retailer negotiates with the end user a price for delivered gas, which includes the price of the gas commodity, the price of transportation of the gas and the retailer's own costs and margin. The retailer can approach its associated distributor and they can negotiate a distribution price that is high, so that the retailer covers its costs but does not make a margin (although the parent company maintains its profit levels). Another retailer would then be unable to compete on the delivered price of gas, even though the distributor offers the same price for its services.

In the draft report for this inquiry, the Commission examined whether there was a case for changing the associate contract provisions in relation to contracts for reference services. The Commission proposed that in these circumstances the costs could be reduced by amending s.7.1 of the Gas Code, such that the service provider is required to notify the regulator of its intention to enter an associate contact for the supply of services at the reference tariff, rather than being required to seek authorisation.

However, a number of participants expressed concerns about this proposal. The ACCC considered that requiring approval of associate contracts for services at the reference tariff ensures that the regulator is adequately informed and provides a remedy where the contract does have the effect of substantially lessening competition:

> Requiring approval of these contracts provides an accessible remedy in circumstances where the regulator finds that such a contract is not for the provision of standard unbundled transmission services or, in the relevant context, does have the effect of substantially lessening competition. Without an approval process the regulator has no recourse within the [Gas] Code to require such a contract to be modified. Recourse to other provisions in the TPA [Trade Practices Act], such as s.46, is often untimely and evidentially difficult. The current onus of proof allows for recourse in such circumstances and is unlikely to be lengthy or costly. (ACCC, sub. DR101, p. 56)

The Economic Regulation Authority questioned whether relying on notification would stop a service provider discriminating in favour of an associate or enable regulators to be adequately informed:

> … even in the limited case of associate contracts for supply at the reference tariff, potential discrimination may arise in favour of associates through changes in terms and conditions that may attach to an associate contract for supply of the reference service as compared with independent third party contracts. (sub. DR116, p. 14)
>
> The question arises for a regulator whether he’s adequately informed if he simply is notified about the terms and conditions under which the associate is taking services under this associated contract. (trans., p. 986)

Enertrade argued that a regulator would have insufficient powers if it could not disapprove an associate contract:

> … [the Commission’s proposal to amend s.7.1 of the Gas Code would] not satisfy the concerns of competing retailers and major network customers … While this requirement will allow the regulator to review the contract, it gives the regulator no

> power to amend or cancel the associate contract and does not provide any information or reassurance to the market that the contract is fair and reasonable. (sub. DR98, p. 10)

Some participants noted that if the Commission's notification approach was implemented, the Gas Code would require further changes (Worsley Alumina, sub. DR110, p. 21; Western Power, sub. DR115, p. 41). Western Power argued:

> … further amendments are required to:
>
> (a) oblige the service provider to notify the regulator of the details of the terms of the associate contract as well as of the fact that it has been entered into; and
>
> (b) give the regulator the power to either disallow or vary the associate contract if the regulator forms the view that the associate contract 'would have the effect, or would be likely to have the effect, of substantially lessening, preventing or hindering competition in a market'. (sub. DR115, p. 41)

Participants' concerns about the need for regulators to have adequate information to determine if an associate contract is for a reference service are legitimate. A service provider should submit the contract and any relevant information necessary to satisfy the regulator that the contract is for a reference service at the reference tariff. If the regulator determines that it is materially different from a reference service, then the standard associate contract approval process would apply. In addition, to ensure that the contract does not unduly favour the associate in the terms and conditions, the service provider should provide details of how the terms and conditions differ from reference service contracts with non associates and why this is the case. An arbitrator when settling a dispute over terms and conditions with a non associate could use this information.

The Commission also acknowledges that there might be a circumstance where an associate contract for reference services at the reference tariff could substantially lessen competition in a market. Such a circumstance could arise on a transmission pipeline where a service provider enters a contract with an associate for services at the reference tariff for a large proportion of the pipeline's capacity.

However, in such a circumstance, s.13 of schedule 1 of the Gas Pipelines Access Act potentially ensures that these contracts are not used to lessen competition. Under this section, there are penalties for a service provider or any person (including an associate with the contracted capacity) that prevents or hinders access to a service provided by a covered pipeline. In addition, the regulator or any person affected by such conduct can seek an injunction, declaratory relief or damages in relation to such conduct. One example given of the type of the conduct to which this section applies is 'refusing to sell a marketable parcel (within the meaning of the [Gas] Code) on reasonable terms and conditions'. The terms and conditions associated with the reference service would provide a benchmark for judging what are 'reasonable terms and conditions'.

The Commission considers that changing the associate contract provisions so that regulators do not have to approve associate contracts for reference services would reduce the costs of the associate contract provisions, without necessarily undermining their effectiveness.

FINDING 10.2

The requirement under s.7.1 of the Gas Code that a service provider seek authorisation for the supply of a reference service at the reference tariff imposes costs on the service provider, with little apparent benefit.

RECOMMENDATION 10.1

Section 7.1 of the Gas Code should be amended so that a service provider entering an associate contract for the supply of a reference service at the reference tariff is not required to seek authorisation. However, the service provider must provide the contract and any necessary information to the relevant regulator to satisfy the regulator that it is a contract for a reference service at the reference tariff.

Public release of commercially sensitive information

Some inquiry participants argued that a cost of requiring regulator approval for associate contracts is the potential for the public release of commercially sensitive information, particularly when the regulator conducts public consultation. The AGA, for example, claimed:

> The requirement to present commercial arrangements to a regulatory authority for approval may also place both the service provider and an incumbent retailer at a disadvantage by leading to the disclosure of commercially sensitive information.
>
> The existing associate contract provisions deal with the matter of protecting commercially sensitive material within the agreement. The national Gas Code provides for regulators to conduct public consultations on proposed associate contracts as they consider appropriate. Regulators have generally interpreted this as necessitating a public process including a period for submissions and representations from interested parties. There may be situations, however, where disclosure of the fact that a distribution business is seeking to have a commercial agreement covering, for example, discounted gas transportation tariffs, may lead to a loss of some part of the net present value of benefits sought by the commercial arrangement. (sub. 13, p. 86)

The Gas Code affords regulators some discretion in determining whether information is genuinely commercially sensitive. Section 7.3 of the Gas Code states:

> The Relevant Regulator must not make public any part of the Associate Contract which the Service Provider claims is confidential or commercially sensitive except where the Relevant Regulator is of the opinion the disclosure of the part of the Associate Contract concerned would not be unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User.

Generally, regulators have upheld service providers' claims of confidentiality when conducting public consultations. However, in some cases, the regulator has chosen to release some of the contract details to aid the public consultation process. One example is the Independent Pricing and Regulatory Tribunal's consultation on a proposed variation to a contract between AGL Gas Networks and AGL Retail (IPART 2003).

The Commission recognises the potential costs to the service provider and their associates arising from the release of confidential information while complying with the associate contract provisions. However, the provisions in the Gas Code to protect the release of confidential information address these concerns. The Commission notes that regulators have generally accepted service providers' claims of confidentiality or, in other cases, have released only limited information.

Administrative costs of compliance

The costs of compliance with the associate contracts provisions of the Gas Code might vary with the discretion of regulators in defining what constitutes an associate contract. Although an associate is defined in the Gas Code (using various sections of corporations law) for determining what constitutes an associate contract, several inquiry participants noted an inconsistency in the definition used by different regulators.

One particular definitional issue raised by inquiry participants was whether a contract between a service provider and an affiliate business for the management of pipeline operations (an asset management contract) should be defined as an associate contract under the Gas Code. Generally, regulators have not sought access to such agreements for approval. An exception is the QCA, which sought access to a contract between ENERGEX and Allgas Energy for ENERGEX to manage the gas network assets on behalf of Allgas Energy. The AGA (sub. 13, p. 85) provided a table to demonstrate the inconsistency of this approach across regulators (reproduced here as table 10.4). The relationships among asset managers, network owners and retailers are detailed in chapter 2.

Several inquiry participants were concerned that defining asset management contracts or service agreements as associate contracts is inconsistent with the objectives of the associate contract provisions, which relate to the impact of contracts between associates on downstream retail markets. The AGA, for example, claimed:

> The associate contract issue was principally an issue about related entities downstream in the market, for example, between a gas distribution network owner and an associated retail party, and those contract provisions are important to give other retailers, who don't have an associated network owner upstream, for example, confidence that they are being dealt with on an arm's length basis with other retailers, for example. That's an important policy objective and we have no issue with that but we do have an issue with service agreements being redefined as associate contracts where there is actually a contestable market for asset management services and arm's length transactions happening there. (trans., p. 25)

Table 10.4 **Regulatory treatment of asset management contracts**

Jurisdictional regulator	*Service providers with agreements*	*Significant contracting party*	*Type of contract*	*Has the regulator been provided with or approved the agreement?*	*Has the regulator sought access?*
Essential Services Commission (Victoria)	United Energy	National Power Services	Asset management	No	No
	Envestra	Origin Energy Asset Management	Asset management	No (not an associate)	No
	TXU Networks	Tenix, Abigroup	Technical asset management	No (neither an associate)	No
Independent Pricing and Regulatory Tribunal (NSW)	AGL Gas Networks	Agility	Asset management	No	No
South Australian Independent Pricing and Access Regulator[a]	Envestra	Origin Energy Asset Management	Asset management	No (not an associate)	No
Queensland Competition Authority	Allgas Energy	ENERGEX	Asset management	No	Yes
	Envestra	Origin Energy Asset Management	Asset management	No (not an associate)	No
OffGAR[b] (Western Australia)	Alinta	National Power Services	Asset management	No	No

[a] The Essential Services Commission of South Australia has assumed the responsibilities of this regulator. [b] The Economic Regulation Authority has assumed the responsibilities of this regulator.

Source: AGA, sub. 13, p. 85.

Allgas Energy claimed that defining an asset management contract as an associate contract imposes:

> … regulatory control over commercial matters that should be the province of the service provider. (sub. 25, p. 15)

Agility, a wholly owned subsidiary of AGL, has contracts to manage the pipeline assets of Australian Pipeline Trust and AGL Gas Networks (chapter 2). AGL (sub. 32, p. 29) argued that the associate contract provisions should be amended to clarify that they 'only apply to transportation agreements'.

Requiring service providers to gain regulator approval for asset management contracts has the potential to impose costs on service providers. The only reason for regulatory intervention in asset management contracts is to address the possibility of inappropriate transfer pricing (section 10.3). However, a regulator can refuse to approve an associate contract only if the contract has, or is likely to have, the effect of substantially lessening competition. While transfer pricing does not directly impact on upstream or downstream competition, it could have an adverse effect. However, a regulator is unlikely to be able to address effectively inappropriate transfer pricing through seeking oversight of asset management contracts. In any case, because regulators have no information about the costs of asset management businesses, they are unlikely to be able to assess whether contractual conditions are reasonable.

The Commission has recommended that the issue of transfer pricing be addressed through extending regulators' information collection powers under s.4 of the Gas Code so that they apply to an associate of a service provider undertaking activities under service agreements and contractual arrangements (recommendation 10.3). If such a change were adopted, then regulators would have no valid reason to seek oversight of asset management contracts. In this case, the Gas Code could be amended to make this explicit.

FINDING 10.3

Approval of asset management contracts under the associate contract provisions is unnecessary.

RECOMMENDATION 10.2

The associate contract provisions should be amended to clarify that these provisions do not apply to asset management contracts.

10.3 Service agreements and asset management contracts

Some inquiry participants were concerned about the potential for service providers to use service agreements and asset management contracts to undermine the regulatory framework under the Gas Access Regime. A service provider can enter into these agreements and contracts for network or pipeline operations, maintenance, metering and other activities. Agility (a wholly owned subsidiary of AGL) for example, offers infrastructure management services including customer management, regulatory compliance, metering and incidence response management (Agility 2004).

A service provider might separate its asset ownership from asset management or operations to generate efficiencies. That is, it might be the business strategy of the service provider to separate out its core business functions (including asset management) to achieve efficiencies through specialisation and the introduction of greater transparency in the performance of the individual business units. This was noted by AGL:

> Infrastructure industries in Australia are on the verge of a process of further restructuring which is expected to lead to greater contracting out of asset management and operation services, which are presently, and for the most part, provided in-house. This will lead to greater competition in the provision of those services, and compared with the alternative of independent stand-alone businesses or services, has the potential to produce significant economic efficiencies through sharing of resources and economies of scope and scale. (sub. DR84, p. 33)

However, concerns about the use of service agreements and asset management contracts arise in two cases:

- where a service provider enters service agreements or contracts with an associate for operation or management of its transmission pipeline or distribution network
- where a retailer or producer (or its associate) becomes the operator of a pipeline that services its business.

Agreements and contracts with associates

In some cases, service providers have contracted out the role of operating and/or managing the pipeline to an associate. Agility, for example, manages the distribution assets of AGL Gas Networks in New South Wales. Agility and AGL Gas Networks are both wholly owned subsidiaries of the parent company AGL.

Under such a structure, the asset manager can engage in inappropriate transfer pricing, undermining the process of setting appropriate reference tariffs. Such transfer pricing occurs when a regulated service provider pays the associated asset manager an inflated price in order to raise its own cost structure, thus increasing the reference tariff for services provided by the regulated business. The affiliated asset manager makes inflated profits, which are ultimately passed through to the parent company. A number of participants highlighted the transfer pricing issue:

> A recent development is for regulated businesses to set up separate business units for construction and operation and to implement transfer pricing arrangements … 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. (BHP Billiton, sub. 26, pp. 97 and 120)

> The efficiency of the market will not benefit by cross-subsidisation by third party users of a competing business affiliated to the pipeline service provider. Such cross-subsidisation could occur where services are provided to an affiliated business under a transfer pricing arrangement or where an asset management business passes its costs through to the shippers. (ExxonMobil, sub. DR78, p. 7)

Similarly, the ACCC noted:

> Associate contracts entered into on a non arms-length basis can potentially result in inefficient prices being passed on to users. This is a particular concern where management service contracts are entered into with related parties. (sub. DR101, p. 55)

The extent to which transfer pricing is likely to be a problem will vary across transmission pipelines and distribution networks, and depends on:

- the parent company's ownership share of both the service provider and associate. The larger the parent company's share of ownership in both entities, the greater the incentives to engage in inappropriate transfer pricing
- the proportion of the total costs of the service provider that is attributable to an associate. The larger the proportion the more potential for inappropriate transfer pricing.[1]

One option to address the problem of transfer pricing is to enable regulators as part of a service provider's access arrangement review, to gain sufficient information on the costs associated with the activities undertaken by an associated business. If a regulator considers an associated businesses costs are inappropriate then it could require the service provider to amend the access arrangement to reduce these costs.

[1] Under AGL's latest proposed access arrangement, service contract costs were around 74 per cent of operating costs, or 25 per cent of total costs (AGL 2003).

The current Gas Access Regime has a number of provisions that provide regulators with powers to collect information. However, there are differing views regarding whether these powers were sufficient to enable regulators to assess the reasonableness of the costs incurred for activities undertaken by associated businesses. Some participants argued that these powers were inadequate and needed to be extended:

> Regulators do not appear to have the power to require maintenance and provision of reliable information to substantiate the reasonableness of costs, in particular costs attributable to activities undertaken under service agreements and contractual arrangements with associated businesses … (Office of Gas Access Regulation, sub. 40, p. 20)
>
> 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. (BHP Billiton, sub. 26, p. 120)

The ACCC acknowledged that transfer pricing issues might be dealt with:

> … by giving the regulator power to review the costs of an affiliate that has been contracted to manage the assets of a pipeline as part of the access approval process. (ACCC, sub. DR101, p. 56)

Other participants argued that regulators' powers were adequate in this regard. The ENA claimed:

> … there is an extensive range of existing information powers under the regime. As an example, s.41 [schedule 1 of the *Gas Pipelines Access Act*] provides regulatory authorities with the power to request information believed to be held by any person that may assist a regulator in carrying out its designated functions under the regime. This provision is not limited in application to the service provider, or asset owner.
>
> Further, the current [Gas] Code provides regulatory authorities with the ability to obtain information and undertake benchmarking of the asset owners' costs (subject to the inherent imprecision of comparative data). There is no need for any further power. (sub. DR85, pp. 27 and 28)

Further, a number of participants argued that extension of regulators' powers would stifle the evolution of the competitive market for infrastructure management and operations:

> It is critical to the evolution of competitive markets for the provision of infrastructure services that provisions are not imposed that discourage the efficient use of shared resources and/or are likely to stifle the evolution of competitive markets for the provision of infrastructure services. That would be very likely to occur if regulatory authorities were to review the costs of the affiliated asset management business as part of the access arrangement review, given the current state of evolution of asset

> management contracting and the manner in which the [Gas] Code presently operates. (ENA, sub. DR85, p. 27)
>
> The risk of extending the regulatory process to associated businesses, and particularly given the current regulatory approach to sharing of efficiency gains, is that the businesses would be denied any share of the synergy benefits that may be generated … thereby removing any incentive for investors to undertake these forms of restructuring. The restructuring will not proceed, and the potential efficiencies will not be realised. (AGL, sub. DR84, pp. 34–5)

In addition, the ENA argued that service providers already have incentives to provide regulators with relevant information to justify costs, including those incurred by affiliated businesses:

> Another reason that further information requirements being placed on affiliated asset management businesses are unnecessary and inappropriate is that the service provider has the maximum possible incentives under the existing 'propose–respond' regime to justify and explain levels of forecast or past costs. Failing to provide sufficient supporting evidence in relation to the levels of these costs has the potential to seriously damage the financial sustainability and profitability of the business concerned over the next regulatory period. (sub. DR85, p. 28)

The Commission's assessment

The Commission is concerned that the information collection powers of regulators are not sufficient to address adequately the potential transfer pricing problem. Even though a service provider might provide aggregate information on the costs of an asset manager or service contracts, this is unlikely to be sufficiently detailed to enable the regulator to adequately assess the costs of activities undertaken by associates. Currently, regulators have no powers to compel an associate to establish and maintain more detailed cost information for this purpose. In addition, given the incentives on both the service provider and the associate to transfer price, the contract between the parties could be designed to ensure relevant information cannot be provided, such as including confidentiality provisions.

Although regulators can use s.41 of schedule 1 of the Gas Pipelines Access Act to obtain information from any person, there are problems with using this section. First, it is perceived to be heavy handed because any person that breaches it could incur criminal sanctions (12 months imprisonment) (ACCC, sub. 48, p. 104). Second, it only enables a regulator to obtain information that a regulator 'believes' exists and that has been kept by the associate. The Economic Regulation Authority noted:

> It is clear that even s.41 [schedule 1 of the *Gas Pipelines Access Act*] may be ineffective if no historical actual information is recorded. Since an access arrangement

> is a forward looking document presenting information for the projected access arrangement period, the basis for allocating joint costs is itself merely an estimate.
>
> Verification of projected data against actual historical information may be further frustrated if there is outsourcing of work by the service provider to associate asset management companies or to other contractors and inadequate records are kept by either the service provider or associate companies. (sub. DR116, p. 18)

An option to address the issue of transfer pricing is to extend the information collection provision under s.4.1 of the Gas Code. In particular, an associate should have to establish and maintain accounts in relation to activities undertaken for a service provider under service agreements and contractual arrangements and provide these accounts at the time of the service provider's access arrangement review. These accounts would provide more detailed information than currently available and enable a regulator to 'benchmark' more effectively the associate's costs against other businesses offering similar services. If the regulator considered that the associate's costs were inflated then it could disallow (or reduce), the service provider's costs attributed to service agreements and contractual arrangements with associates in the access arrangement.

A regulator should also be able to issue guidelines in relation to the associate accounts to ensure the maintained information is suitable. In addition, when a service provider enters a contract with an associate, the contract terms and conditions should ensure the regulator is able to apply these information provisions.

The Commission notes that the extension of information collection powers will increase the costs of the Gas Access Regime. These costs might include administrative costs to an associate and efficiency losses from reduced incentives to use infrastructure management businesses, even in circumstances where the use of these businesses is justified on commercial grounds. However, the Commission considers that in some circumstances the potential costs of transfer pricing could be greater than these costs.

As noted above, the transfer pricing problem is likely to be greater on certain transmission pipelines and distribution networks. The information collection requirements, therefore, should only extend to associates where the regulator considers the potential for, and costs of, transfer pricing are significant. Where a parent company, for example, owns a large share of both the associate and the service provider and where the costs attributable to the associate are a significant proportion of the total costs of the covered transmission pipeline or distribution network.

RECOMMENDATION 10.3

To ensure regulators can adequately assess the costs of an associated business that undertakes activities under service agreements and contractual arrangements with a service provider in relation to a covered pipeline, the following subsections should be added to s.4.1 of the Gas Code:

s.4.1B An Associate of a Service Provider of a Covered Pipeline that undertakes activities under service agreements and contractual arrangements with a Service Provider in relation to the Covered Pipeline must (if requested by the Relevant Regulator):

(a) establish and maintain a separate set of accounts in respect of the Services provided to the Covered Pipeline

(b) allocate any costs that are shared between an activity that is covered by a set of accounts described in s.4.1B(a) and any other activity according to a methodology for allocating costs that is transparent.

s.4.1C A Service Provider when entering service agreements and contractual arrangements with an Associate for activities undertaken in relation to a covered pipeline, must ensure that the terms and conditions of the contract will allow s.4.1B to be implemented.

RECOMMENDATION 10.4

To ensure regulators can adequately assess the costs of an associated business that undertakes activities under service agreements and contractual arrangements with a service provider in relation to the covered pipeline, the following subsection should be added to s.4.2 of the Gas Code:

s.4.2A In complying with ss4.1B(a) and (b) an Associate of a Service Provider must:

(a) if the Relevant Regulator has published general accounting guidelines for Associates which apply to the accounts being prepared, comply with those guidelines; or

(b) if the Relevant Regulator has not published such guidelines, comply with guidelines prepared by the Associate and approved by the Relevant Regulator or, if there are no such guidelines, comply with such guidelines (if any) as the Relevant Regulator advises the Associate apply to that Associate from time to time.

Such guidelines may, amongst other things, require the accounts to contain

sufficient information, and to be presented in such a manner, as would enable the assessment (and benchmarking) by the Relevant Regulator of the costs of the activities undertaken in relation to the Covered Pipeline by an Associate under service agreements and contractual arrangements with a Service Provider.

In chapters 5 and 7, the Commission recommended deletion of potentially conflicting objectives from various sections of Gas Access Regime, including instructions to the regulator to undertake tasks according to methods that are 'otherwise fair and reasonable'. The ring fencing provisions should also be amended in this regard.

RECOMMENDATION 10.5

To remove potentially conflicting objectives from the Gas Access Regime, s.4.1(e) of the Gas Code should be amended to delete reference to the term 'otherwise fair and reasonable'.

Agreements and contracts with entities that have upstream and downstream market interests

The second case in which concerns about service agreements and asset management contracts arise is where gas producers or retailers became involved in the management or operation of transmission pipelines or distribution networks. In Victoria, Queensland and South Australia, for example, Origin Energy Asset Management, a wholly owned subsidiary of Origin Energy (a gas retailer), manages and services distribution networks.

Such arrangements might provide a competitive advantage to a gas retailer or a producer that is an asset manager or operator, through:

- accessing information about competitors' future plans or customers
- operating the distribution network or transmission pipeline in a way that disadvantages its competitors, by limiting or disrupting access to services.

BHP Billiton raised concerns in this regard, noting:

> … the fact that … [Envestra's] networks are operated by an entity that is also a retailer and producer could be expected to provide … [the operator] 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. (sub. 26, p. 104)

If adopting a role as an asset manager or operator provides retail or production businesses with an advantage over competitors, then such an arrangement could undermine the objectives of the ring fencing provisions of the Gas Code. However, some participants argued that there was already sufficient oversight of these arrangements under the ring fencing provisions:

> Asset owners are well aware of the importance of observing ring fencing requirements. Any asset owner will, as part of its normal contractual arrangements, require the [operator] … to abide by the asset owners' statutory obligations, including ring fencing. (AGL, sub. DR84, p. 38)
>
> … it is not necessary [to require asset management businesses to comply with ring fencing arrangements] as any asset owner in any contract as part of its normal contractual arrangements will require the … [asset manager or operator] to abide by the asset owners' statutory obligations, including ring fencing obligations. (ENA, sub. DR85, p. 27)

Under ss4.1(f) and (g) of the Gas Code, a service provider must ensure that a user's confidential information is only used for the purpose for which it was provided and is not disclosed to any other person without the user's consent. Further, under ss4.12–4.13, a service provider:

- must establish and maintain appropriate procedures to meet these requirements
- may be required, by the regulator, to demonstrate the adequacy of these procedures
- must provide to the regulator a report describing the measures taken to comply with these requirements.

There are penalties associated with breaches of ss4.1(f) and (g). In addition, because these are conduct provisions, the regulator or any person affected by breaches of the provisions can seek an injunction, declaratory relief or damages in relation to such conduct.

The current Gas Access Regime appears to be adequate to ensure that service providers entering contracts with pipeline operators or managers will have in place procedures that protect users' information. The Australian Pipeline Trust, for example, in its ring fencing compliance report for the Moomba–Sydney pipeline noted:

> … [that it] had required contractors having access to confidential information to observe the requirements of the [Gas] Code in relation to such confidential information. (APT 2003, p. 4)

The Gas Access Regime also addresses the incentive for an asset operator to undertake anticompetitive behaviour by operating its distribution network or transmission pipeline in a way that disadvantages its competitors (or competitors of its associates). Section 13 of schedule 1 of the Gas Pipelines Access Act prohibits an operator[2] from engaging in conduct for the purpose of preventing or hindering the access of another person to a service provided by a covered pipeline. Breaches of this provision attract a maximum civil penalty of $100 000. In addition, because this is a conduct provision, the regulator or any person affected by breaches of the provision can seek an injunction, declaratory relief or damages in relation to such conduct.

The Commission also notes that Origin Energy Asset Management, which has affiliated businesses in upstream and downstream markets, is already a ring fenced entity:

> Origin Energy Asset Management (OEAM) is a ‘ring fenced’ organisation, separated from the retailing of natural gas carried out by Origin Energy Limited.
>
> The National Third Party Access Code [the Gas Code], enacted on July 28, 1998 to facilitate deregulation, requires the separation of network distribution activities from the natural gas production or retailing activities of a related business.
>
> This separation of functions and staff prevents retailers from gaining access to customer information that would give them a competitive advantage over other retailers. (Origin Energy 2004)

FINDING 10.4

The Gas Access Regime already provides adequate safeguards to ensure that asset operators and managers that undertake activities in upstream and downstream markets do not use their operation and management roles to behave anticompetitively.

[2] Section 13(1) actually refers to ‘a person who is a party to an agreement with a service provider relating to a service provided by means of a [Gas] Code pipeline’.

11 Administrative and appeal processes

As discussed in chapter 4, the Commission has concluded that the decision making processes under the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime) fall short of best regulatory practices in a number of areas and that there is scope for improvement. The time taken to make decisions under the Gas Access Regime has often been beyond the indicative time limits specified in the legislation, and the accountability mechanisms in place have some shortcomings.

Examined in this chapter are the sources of delay for decisions under the Gas Access Regime, along with proposals to address this problem. Much discussion relates to proposals for access arrangements with a reference tariff. The appeal arrangements are examined to check whether they provide the best incentives for regulators to make accountable, well reasoned decisions. The funding arrangements are also considered.

11.1 Timeliness

Timely decision making is important for economically efficient outcomes. Delays in reaching regulatory decisions have an impact on the commercial operations of affected businesses (chapter 4). The business activities of pipeline owners or operators (service providers) are significantly affected by decisions on coverage, access arrangements, ring fencing and associate contracts. Decisions under the Gas Access Regime might also have a significant effect on the business outcomes of an upstream or downstream pipeline user.

Many inquiry participants provided reasons for delays, including:

- lack of binding time limits in the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code)
- processes for access arrangement approval
- transitional and pipeline-specific circumstances
- the lack of incentive for service providers to expedite the process.

Each of these aspects are examined in the following paragraphs.

Time limits in the Gas Code

The Gas Code has time limits for most decisions (box 11.1). A final recommendation by the National Competition Council (NCC) on coverage (or revocation of coverage) from the time an application is received should take a maximum of three months. A decision by the Minister on coverage (or revocation of coverage) should be made within 21 days of the NCC's recommendation. A service provider is required to submit a proposed access arrangement to the regulator within 90 days of a pipeline becoming covered, and the regulator should decide whether to approve this access arrangement within six months. The Gas Code also includes indicative time limits for other decisions, such as ring fencing, dispute resolution and associate contracts.

The Gas Access Regime gives regulators and Ministers discretionary powers to grant time extensions. The NCC and Ministers can increase the period for coverage recommendations and decisions, provided they publish a national newspaper notice. A regulator assessing an access arrangement can extend approval time by two months, and this extension can be repeated.

The powers to extend decision making times under the Gas Access Regime mean that time limits in legislation are only indicative. Minsters and regulators thus have the opportunity to take longer than the indicated times. As Epic Energy noted, 'the system gives a regulator total control of the regulatory timetable' (trans., p. 167).

WMC Resources noted indicative time frames entail a lack of pressure on regulators to make decisions within the specified period:

> While WMC Resources understands that regulators use their best efforts to minimise delays, there is no real mechanism in the [Gas] Code which regulators can use to ensure that the time frames contained in the Code are adhered to. (sub. 43, p. 11)

Under the Gas Access Regime, coverage decisions have tended to take place within the specified time frames. Most recommendations have been made within three months and most decisions by Ministers have been made within one month (appendix C, tables C.3 and C.4). An exception is the application by East Australia Pipeline (now trading as Australian Pipeline Trust) for revocation of coverage of the Moomba–Sydney pipeline system. The application was made in June 2001 and the NCC recommended in November 2002 that coverage not be revoked. The Minister's decision to revoke coverage for the Moomba–Marsden part of the pipeline system and retain coverage for other parts was made in November 2003.

For access arrangements, the discretion afforded to regulators to extend the time for making decisions has led to significant delays in decision making (table 4.2).

Box 11.1 **Time limits in the Gas Code**

Coverage

- On receiving an application for coverage (or revocation of coverage), the NCC must publish a national newspaper notice. No more than 35 days after the notice is published, the NCC must prepare a draft recommendation on the application. No more than 28 days after the draft recommendation, the NCC must submit a recommendation to the relevant Minister on whether the pipeline should be covered (or whether coverage should be revoked).
- However, the Gas Code provides flexibility for the NCC to increase the period for doing these things (any number of times), provided the NCC publishes a national newspaper notice.
- Within 21 days of a coverage recommendation, the Minister must make a decision. Like the NCC, the Minister can increase the period for doing this (any number of times), provided he/she publishes a national newspaper notice.

Access arrangements

- A service provider has 90 days from the date of coverage to submit a proposed arrangement and access arrangement information to the regulator (s.2.2).
- The relevant regulator must issue a final decision within six months of receiving a proposed access arrangement (s.2.21).
- This process includes:
  - public consultation (there must be at least 28 days for receiving submissions)
  - a draft decision
  - further public consultation (there must be at least 14 days for receiving submissions)
  - a final decision
  - if necessary, the submission of a revised access arrangement and a further final decision (with at least 14 days available for the service provider to resubmit).

  If the service provider fails to submit an access arrangement, or incorporate amendments satisfactory to the regulator, then the regulator must draft and approve its own access arrangement.
- Section 2.22 of the Gas Code provides the regulator with the ability to increase the six month period up to two months on one or more occasions. There is no limit to the number of times that the regulator may increase the time for a final decision.

Ring fencing

- Service providers must comply with the ring fencing provisions in the Gas Code within six months of the pipeline becoming covered (s.4.1).

(Continued next page)

Box 11.1 (continued)

- In some cases, the regulator may impose additional ring fencing obligations. The regulator must carry out a public consultation process. The Gas Code indicates time frames for each step in the public consultation process, suggesting the process should take around 60 days.
- Similarly, if a service provider applies to have ring fencing obligations waived, the public consultation process to be followed has indicative time frames, suggesting the process should take around 60 days.

Dispute resolution

- The arbitrator must provide a final decision within three months of requiring parties to a dispute to make submissions (s.6.11).
- The arbitrator may increase the period by up to one month on one or more occasions without notice (s.6.12).

Other

- Section 5 of the Gas Code sets time frames for service providers to respond to information and access requests from access seekers.
- The regulator is deemed to have approved an associate contract application if it does not notify the service provider otherwise within 21 days (s.7.4). (If the regulator conducts a public consultation in relation to the associate contract, the period is 49 days [s.7.5]).
- The regulator has discretion to extend the period that applies to any person (other than the regulator, relevant Minister or the NCC) on any number of occasions, provided it receives the application for extension before the relevant time period expires (s.7.19).

Source: Gas Code.

Process issues

It has been suggested that the process for approving access arrangements has led to delays in decision making. The process involves a minimum of two rounds of public consultation and two decisions. If the access arrangement is still not approved, there might be further negotiation between the service provider and regulator, leading to a further final decision.

Due to the complex nature of the Gas Code, each stage of the decision making process potentially involves the resolution of complex issues. The Economic Regulation Authority (ERA, which has assumed the responsibilities of the former Office of Gas Access Regulation, OffGAR), noted that it might be necessary to seek legal advice, publish discussion papers and take other steps to reduce the likelihood of reviewability at courts (trans., p. 81).

The Australian Competition and Consumer Commission (ACCC) suggested that one source of delay is a lack of restraint on service providers to propose amendments to access arrangements during the approval process:

> There is nothing in section 2 of the [Gas] Code that appears to prevent a service provider from submitting amendments to a proposed access arrangement on an on-going basis. (sub. 48, p. 83)

The ACCC noted that further amendments might need additional consultation and possibly the publication of additional preliminary views by the regulator. This can be very time consuming.

> There have been cases where service providers have submitted several rounds of amendments to the first access arrangement originally submitted for approval. While some flexibility is required, it is important to recognise that each time a service provider amends its proposed access arrangement; the relevant regulator is required to ensure that all interested persons are treated fairly. In many cases this requires a further round of consultation. This can make the timely consideration of a proposed access arrangement impossible. (ACCC, sub. 48, pp. 83–4)

A further problem arises if the service provider incorporates a substantial amount of new information into revised access arrangements. The ACCC cited an example of where a service provider had submitted a substantially new access arrangement after a draft decision (sub. 48, p. 84). When this happens, the regulator is required to restart its analysis and assessment process, which is likely to push out the date of the final decision.

Transitional and pipeline-specific issues

Some participants suggested that delays in approving access arrangements are principally due to transitional issues arising from the implementation of a new regulatory regime:

> The Gas Code is still in its infancy and thus it is not surprising that there have been uncertainties and delays associated with its implementation. (Chamber of Commerce and Industry of WA, sub. 39, p. 5)

> The first round of access arrangements was a training exercise and an exercise for many of the participants. There were issues … for example, initial capital bases, that needed to be addressed which were one-off issues. (Envestra, trans., p. 835)

There are also broader transitional issues for the gas industry, which have interacted with decisions under the Gas Access Regime. Many pipelines have undergone changes in ownership as a result of broader reforms to the gas industry (chapters 2 and 3). In addition, most pipelines covered by the current Gas Access Regime have previously been covered by other access regimes. Issues have had to be resolved for some pipelines making this transition to new regulation.

The ERA noted the Dampier–Bunbury pipeline decision was complicated by the regulator's need to account for matters related to the sale of the pipeline to its current owner (which resulted in confidential submissions and judicial review). The Goldfields Gas Pipeline decision was complicated by the regulator's need to account for the interaction of the Gas Code with the previous regime (the State Agreement) (sub. 40, pp. 12 and 14).

Lack of incentive by service providers (and others) to expedite the process

Interested parties might not have an incentive to progress access arrangements under the Gas Access Regime. When the terms and conditions of an access arrangement are being considered by the regulator and differ from those that currently exist, some party might have an incentive to delay the process.

Many pipelines in schedule A of the Gas Code, for example, were regulated under a different access regime before the Gas Access Regime was implemented. When the reference tariff under the then existing regime was above that acceptable to the regulator under the Gas Access Regime, service providers had an incentive to delay the decision. WMC Resources noted:

> … there is no incentive on the part of the service provider … to expedite the finalisation of the access arrangement. Any gains made by the provider in setting access prices artificially high are retained by the provider. Service providers therefore have an incentive to delay the regulatory process for as long as possible and retain the benefits of high access prices. (sub. 43, p. 19)

Three ways in which an interested party might seek to delay the process are:

- *judicial review* — challenging decisions in a court of law, by initiating proceedings for an injunction or a declaration that the law was not applied correctly (section 11.2)
- *merits review* — challenging decisions through the merits review process which puts a stay on the decision in some cases (section 11.2)
- submitting new material to the regulator up until the time of each decision.

In addition, the Hunter Gas Users Group noted that the delay might be caused by the service provider's failure to provide sufficient information to satisfy the regulator:

> … regulators and gas users … face a resource and information asymmetry problem in all access reviews and much of the delays caused are due to withholding of information. (sub. 4, p. 6)

FINDING 11.1

There are valid concerns about the inadequate timeliness of regulatory decisions in some cases under the Gas Access Regime.

Measures to improve timeliness

A number of recommendations in other chapters of this report should indirectly help to improve timeliness. Issues of timeliness are also likely to be less significant in the future given that the first round of access arrangements is nearly complete. As noted by the ERA:

> The Authority expects … processes to become less time consuming now that the first round of approvals is almost completed nationally and evidence is gathering that scheduled revisions of access arrangements are being handled expeditiously. (sub. DR116, p. 14)

However, there are several ways to improve directly the timeliness of decisions under the Gas Access Regime. Options canvassed by inquiry participants include:

- default decisions for coverage
- limiting the ability of regulators to extend time periods for access arrangement decisions
- introducing backdating provisions for access arrangements
- removing the further final decision from the access arrangement approval process
- limiting service providers' opportunities to submit amendments to access arrangements after the regulator's draft decision.

Default coverage decisions

In the draft report, the Commission considered the merits of introducing a stricter timetable for decisions by Ministers. The Commission supported retaining the indicative time frame in the Gas Code (21 days) and in addition, recommended that the NCC's recommendation would be agreed in the absence of a Ministerial objection within that period.

Some participants supported this recommendation (NCC, sub. DR92, p. 3; BHP Billiton, sub. DR96, p. 7; and ACCC, sub. DR101, pp. 56–7). However, several participants raised concerns about this proposal. The main concern was that it is the Minister, and not the NCC, that is ultimately responsible for the decision on coverage. The Minister is accountable for the decision and must defend it in both merits and judicial reviews. Participants argued that, as the Minster is the final decision maker, it is inappropriate for the NCC to be a defector decision maker.

> … the NCC is not directly accountable for the recommendations it makes in the sense that it is under no threat of any adverse consequence from making errors of judgment or misinterpreting the [Gas] Code in the execution of its responsibilities. … The risk with the Commission’s proposal … is that the responsibility of the Minister and the accountability engendered by his involvement will be diluted. (Goldfields Gas Transmission, sub. DR88, p. 43)

> AGL [Australian Gas Light Company] considers that it is appropriate that the relevant Minister … have a positive obligation to make [the coverage/revocation] decision within a particular time frame. The draft recommendation put forward by the Commission would have the effect that the NCC, in some circumstances, becomes the de facto decision maker. (AGL, sub. DR84, p. 41)

> The Ministerial decision making process is a fundamental step in the coverage process yet the Commission’s proposal could render the Ministerial decision making process a ‘rubber stamp’. (Australian Pipeline Industry Association, sub. DR100, p. 58)

Other participants noted that the Ministerial decision is not merely a review of the NCC’s findings, but is an independent assessment, and it is possible for the Minister to arrive at a different conclusion, as was the case with the Moomba–Sydney pipeline revocation of coverage decision (Macfarlane 2003a). For this reason, the Minister might need to be given time to assess the recommendation of the NCC:

> Given the potential complexity of issues which may need to be addressed in a ministerial review of an NCC recommendation, it does not seem reasonable to require a Minister to provide specific grounds within 21 days for rejecting a recommendation. (Goldfields Gas Transmission, sub. DR88, p. 44)

The Commission considers that the reasons presented by participants are compelling and it is not appropriate for there to be provisions for a default Ministerial decision. Furthermore, decisions on coverage and revocation have tended to be made within the specified time period (appendix C, tables C.3 and C.4). Consequently, the Commission endorses the current requirements of the Gas Code which require a decision by the Minister in 21 days, with provision for extension. In the interests of greater transparency, the Commission considers that when extending the time limit beyond 21 days, the Minister should continue to provide a public notice. In most cases there will also be good public policy reasons for the Minister to articulate the reasons for the delay.

Extensions

One way to improve timeliness of access arrangement decisions under the Gas Access Regime is to limit the ability of regulators to extend time periods. This could take the form of either mandatory time limits or less discretion to extend time limits.

Stricter time limits have the advantage of achieving outcomes more quickly, thus allowing businesses to pursue commercial activities with more certainty and free resources diverted to regulatory processes. They also provide a strong discipline on parties to gather information quickly and present it to the regulator. Under the existing Gas Access Regime, parties might lack the incentive to present all material quickly if they perceive a strategic advantage from delaying the process and slowly revealing their information. Nothing in the legislation restricts service providers from submitting amendments to the regulator up until the time a decision is made. If they know the regulator can extend the period when it receives new information, service providers might take advantage of this feature. However, if the regulator must make a decision by a specified date, it is in the interest of service providers to gather information and present it to the regulator promptly.

A disadvantage of reducing the discretion of the regulator to extend time periods is that good decision making might be compromised if the regulator has less time to make a decision. Access arrangement decisions under the Gas Access Regime deal with complex matters requiring analysis and research. The outcome of decisions could have an impact on service providers' business operations. Such decisions should not be made lightly. In addition, other parties might enter into contracts and investments based on the outcome of decisions made under the Gas Access Regime. If regulators are required to reach a decision within a mandated period, they might not have time to consider all the issues. The basis of the mandated time limit could be eroded if the quicker decision results in an increase in applications to courts and tribunals to review decisions. Moreover, it might not be possible for a regulator to make a decision within the prescribed time if the regulator's decision is being appealed. However, the Commission considers that this issue could be overcome by 'stopping the clock' for the regulator's timetable in the event of a judicial appeal.

There are ways to reduce the discretion of decision makers to extend time periods without imposing mandatory time limits. WMC Resources suggested a stricter burden of proof on interested parties. It argued that a party wanting an extension should have to prove why it is necessary — for example, by verifying that new information was not known and not reasonably available at the time submissions closed (sub. 43, p. 21). The Commission does not consider such requirements would necessarily add to timely decision making. Consultants' reports, for example, might not be available when submissions close and thus could be used by interested parties to delay the process.

WMC Resources also suggested that the regulator should be required to publish the reasons for an extension (sub. 43, p. 21). Under the current requirements of the Gas Code, the regulator is required to publish extension notices in a national newspaper. The Commission considered that there are good public policy reasons why reasons for the delay should accompany this notice, however, it is not convinced that formalising this requirement would add to timely decision making.

In considering the tradeoff between strict time limits and good decision making in its review of the national access regime, the Commission recommended against binding time limits on the basis that practical difficulties and costs associated with rushed outcomes outweigh the benefits of more timely decisions. Instead, the Commission decided that indicative timeframes would provide a valuable discipline on decision making (PC 2001c, pp. 402–3).

Under the Gas Access Regime, indicative time frames have not proven to be a useful discipline on decision makers for access arrangement approval — this outcome is not necessarily due to the regulator not expediting the process, but rather due to the sources of delay discussed above. In response to these concerns, the Commission recommended, in the draft report, that the ability of regulators to extend the time limit for access arrangement approvals be curtailed.

Several participants acknowledged that mandatory time limits could achieve outcomes more quickly and provide a stronger discipline on service providers to present information to the regulator. However, they were uncomfortable with the Commission's proposal to allow regulators to extend time limits only once:

> [The proposal] could cause further delays by increasing applications to courts and tribunals for review of rushed decisions. Additionally, if parts of the decision making process are being disputed before courts or review bodies the time limits may not be achievable. (ACCC, sub. DR101, p. 57)
>
> … it is likely that an 8 month time limit (6 months plus one permitted extension of 2 months) would not be sufficient to enable a well-considered approval to be given in all situations, without a shortening of the process presently provided for in the [Gas] Code. (Office of the Code Registrar, sub. DR103, p. 1)
>
> … AGL considers that it is important, at least in the first few years of operation of the revised regime, that regulators have the ability to extend access arrangement approval processes. AGL considers that the [Gas] Code should provide sufficient flexibility for regulators to grant extensions of time where there are unforseen circumstances. (AGL, sub. DR84, p. 40)
>
> The improvement of … time by allowing regulators only two months' notice … may damage the process itself, given that regulators may not have the information they need

> and they take … decisions under time pressure rather than under knowledge. (ERA, trans., p. 986)

The ERA flagged another undesirable consequence of the proposal — it might create an incentive for regulators to not approve access arrangements because they cannot be satisfied that the access arrangement complies with the Gas Code:

> The Authority is concerned that placing limitations that are too severe on timing for some steps of the process could lead to regulators faced with inadequate information thereby deciding not to approve an arrangement that with the benefit of additional information might be approved as complying. (sub. DR116, p. 14)

However, there was support from some parties (South Australian Government, sub. DR108, p. 4; Epic Energy, sub. DR109, p. 2; and BHP Billiton, sub. DR96, p. 7). Worsley Alumina and Western Power supported the proposal, but cautioned:

> … allowing a regulator to extend the period of time for approval only once may help reduce delays in the approval process, but the effectiveness of this limitation may be undermined by a service provider's delay in providing information, or provision of inadequate information; the access arrangement approval process is a complex one and it should not be compromised by time pressures as this is likely only to lead to error in decision making and lengthy appeals. (Worsley Alumina, sub. DR110, p. 22)

> … the effectiveness of such a limitation may be affected by: (a) the inherent complexity involved in the approval of an access arrangement; (b) judicial review proceedings brought during the approval process; and (c) inadequate information provision to the regulator by the service provider. (Western Power, sub. DR115, p. 42)

Goldfields Gas Transmission sought clarification on whether the recommendation for only one extension of time referred to the entire approval process, or each stage of the regulatory process. It concluded that it supports the proposal as long as 'appeal rights are not diluted' (sub. DR88, p. 40).

Backdating

In the draft report, the Commission's proposal to curtail extensions for time to approve an access arrangement was coupled with a proposal to give the regulator discretion to backdate reference tariffs (for example, to when the service provider first proposed an access arrangement or when the draft decision was made). The Commission considered such a provision might streamline the access arrangement approval phase by increasing the attractiveness to interested parties of an approved outcome (relative to the uncertainties of a delayed outcome). In other words, backdating could reduce the incentive for interested parties to delay settlement.

There was in principle support for backdating from some participants (WMC Resources, sub. 43, pp. 15–19; BHP Billiton, sub. DR96, p. 7 and Worsley

Alumina, sub. DR110, p. 22). However, many inquiry participants considered there were many practical difficulties with applying backdating:

> Backdating powers for regulators may not be in the best interests of due process in decision making, particularly as not all delays emanate from the side of the service providers. This recommendation requires careful evaluation. (Western Australian Government, sub. DR114, p. 13)
>
> … regarding the backdating of reference tariffs: we believe this is fraught with difficulty and risk. (Envestra, trans., p. 835)
>
> AGL considers that, in light of the other changes the Commission has suggested to the Gas Access Regime, it is unnecessary to introduce backdating. AGL also considers that backdating will be complex to implement. (AGL, sub. DR84, p. 41)
>
> In [the] ENA's [Energy Network Association's] members' views, this would lead to issues of complexity, inequity and unworkability in situations where networks and pipelines serve multiple tariff classes, sometimes under a mixture of varying terms and conditions. The ENA does not consider that the proposal is appropriate for these reasons. (ENA, trans., pp. 582–3)
>
> The Government opposes … the backdating of tariffs, as it could create regulatory uncertainty for service providers. (South Australian Government, sub. DR108, p. 4)
>
> The problems [the Commission] identified [with backdating] … are significant issues which have the very real potential to undermine many of the other reforms to the [Gas] Code which the Commission is proposing. In particular, the increased uncertainty for service providers is substantial, particularly where … [most favoured nation] clauses exist. (Goldfields Gas Transmission, sub. DR88, p. 41)

The ACCC, Western Power and Goldfields Gas Transmission provided further detail on the impracticality of backdating under the Gas Access Regime:

> The backdating recommendation is not consistent with the nature of reference tariffs. Reference tariffs form the benchmark for the negotiation of contracts for access. It is doubtful that backdating of tariffs can be applied to contracts where the price is defined without referring to the access arrangement or reference tariff. Further, it may not be possible to retrospectively alter such contracts and it would [be] undesirable to amend parts of those contracts while leaving other parts untouched. (ACCC, sub. DR101, p. 57)
>
> … [backdating could become] another potential source of conflict and litigation, with an aggrieved party able to challenge the regulator's decision to exercise or not exercise the power, and the manner of the exercise of the power, for example, in respect of what date the backdating should commence, what is a comparable service under the approved access arrangement to the service that the user has been receiving, and therefore what is the appropriate price, etc. (Western Power, sub. DR115, p. 42)
>
> If tariffs go up and you backdate tariffs … I have some concerns as to how I would actually … invoice a customer. If that customer is … [a] large or small mining operation … on the brink, and we suddenly backdate a [higher] tariff … what happens if that pushes them over the edge? I mean … there is an issue as to whether it could

> push them into trading whilst insolvent … (Goldfields Gas Transmission, trans., pp. 959–60)

Including a backdating provision in the Gas Access Regime might increase uncertainty for those who are required to make a backpayment. This is problematic where there is no mandatory right of access because service providers might be dissuaded from providing access to seekers until after the final decision (to reduce the risk of incurring a backpayment liability). Moreover, depending on how a most favoured nation clause is drafted, the backdated decision could impact on the foundation customers as well as third party access seekers. This could increase the service provider's investment risk.

The Commission has reconsidered its position in the draft report and now considers that there would be significant practical difficulties in applying backdating. The costs from having a backdating mechanism would outweigh any potential benefits.

The Commission considers some modification of the approval process is required. Indicative time frames have proven not to be a sufficient discipline on parties for timely decisions. The Commission acknowledges the potential costs of stricter time limits. However, there would be benefits from limiting the ability of the regulator to extend the time limit for an access arrangement approval decision. Thus the Commission recommends limiting the ability to extend time limits. In the event of a judicial process being initiated, the regulator's time would be suspended until the completion of the review process.

RECOMMENDATION 11.1

The Gas Access Regime should be amended, whereby the regulator would be able to extend the period for approval of an access arrangement by two months only once. If judicial proceedings commence, the regulator's time should automatically be extended by the length of time taken to complete the judicial proceedings.

Removing the further final decision

An area of possible improvement in the decision making process relates to the number of iterations in approving an access arrangement. Several inquiry participants canvassed removing the further final decision:

> The further final decision … is, in the ACCC's opinion, an unnecessary step in the assessment process. It is relatively rare that a decision making process requires the regulator to, in effect, make two draft decisions. This extra step in the process tends to lessen the importance of the first draft decision, since the service provider has not one but two further opportunities to address the regulator. The final approval causes several months of delay, while adding relatively little to the quality of the decision making

process. The ACCC submits that the final approval could be removed, and that the relevant regulator's consideration of the proposed access arrangement should end with the final decision. (ACCC, sub. 48, p. 85)

In BHP Billiton's view, the efficiency and timeliness of the decision making process would be improved considerably if the final decision were actually final … and [the] additional, unintended, non-transparent and unaccountable [further final decision] step in the process were removed … BHP Billiton considers that the Commission should recommend … changes to the [Gas] 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. (BHP Billiton, sub. 26, p. 117)

In the draft report, the Commission noted that having a further final decision effectively means there are two draft decisions, and that this lessens the significance of the first draft decision. It noted there are good reasons for including a draft decision, but one draft should be sufficient to provide for feedback and amendments. Thus, the Commission proposed removal of the further final decision.

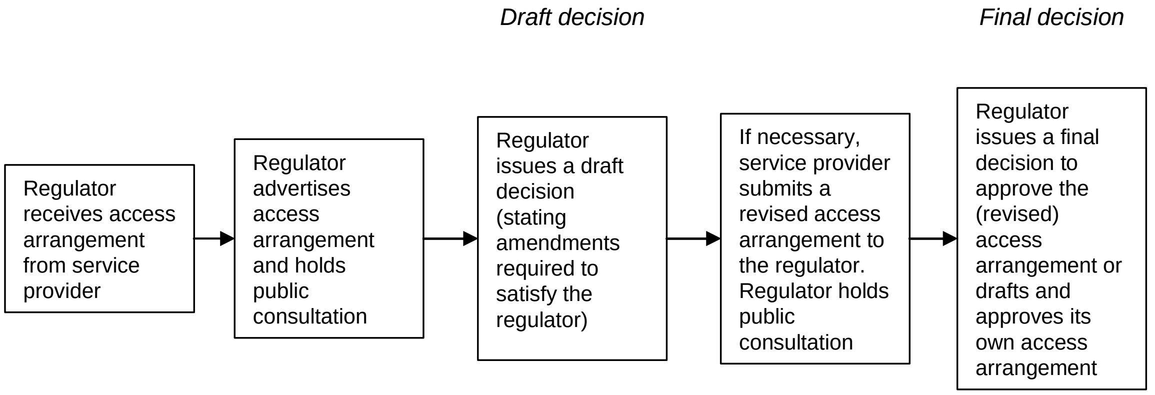
The Commission's proposal was interpreted in two different ways by participants. The South Australian Government thought the service provider would still have an opportunity to make revisions to its access arrangement following the final decision. Thus, it noted: 'it is difficult to see how this step can be avoided if the service provider is to draft the access arrangement' (sub. DR108, p. 5). Similarly, the Office of the Code Registrar and AGL noted respectively:

… if the service provider is to draft the access arrangement in response to the final decision, then that access arrangement will need to be checked by the regulator to ensure that it is in conformity with the final decision. It is difficult to see how this checking can be avoided if the service provider is to draft the access arrangement. (sub. DR103, p. 2)

AGL notes that if the further final decision is to be removed, there would remain the practical necessity for provision for the regulator to confirm whether the access arrangement submitted by the service provider following the final decision did substantially reflect that decision. (sub. DR84, p. 4)

On the other hand, other participants — Envestra, the ERA, the Energy Networks Association (ENA, which has replaced the Australian Gas Association, AGA) and the ACCC — interpreted the recommendation as meaning there could be no opportunity for service providers to revise their access arrangement following the final decision. This is what the Commission intended in the draft report (as summarised in figure 11.1).

Figure 11.1 **Proposed process for access arrangement approval**



Some participants reacted unfavourably to the Commission's proposal for various reasons. Several participants provided justification for the need for a further final decision:

> This approval stage is often required to enable a service provider to lodge a final access arrangement which flexibly meets the key requirements of the regulator for the access arrangement without necessitating that regulatory body to actually prescriptively impose the exact terms of a final approved access arrangement. (ENA, trans., p. 583)
>
> … there is quite a bit of complex analysis to put … into an access arrangement itself. So there has to be a further final decision. (AGL, trans., p. 782)
>
> The secretariat is of the firm view that there is value in the further final decision process under the current arrangements. The service provider gets a chance to respond to the final decision. There's an opportunity to clarify points of difference. There is an ultimate step, if you like, in draft, before the drafting of an access arrangement only as the last resort by the regulator. (ERA, trans., p. 986)
>
> Envestra views this step in the process as one that confirms that the documentation submitted by the service provider is generally in accordance with the requirements of the final decision. (Envestra, sub. DR82, pp. 7–8)

These views accord with the principle, noted by the Office of the Code Registrar, that a service provider should 'formulate and present [its] own access arrangement even when the changes to the access arrangement are required in response to decisions made by the regulator' (sub. DR103, p. 3).

The ENA considered the further final decision important in correcting errors made in the final decision:

> In a number of cases … the further final decision stage has allowed the correction of manifest technical errors made by regulatory authorities, which, if left uncorrected, would have had serious unintended revenue consequences to distribution businesses or required more expensive and time consuming methods of rectification. (trans., p. 583)

Another concern was the interaction of the proposal with material that can be presented to the merits appeal body:

> Were the further final decision step to be removed from the regulatory process, [the] ENA members consider that it would be necessary to review the restrictions on the scope of parties to introduce additional information in a merits review of an imposed access arrangement, to enable parties to be able to present to the merits review body evidence of the impact of the implementation of the final decision. (ENA, sub. DR85, p. 29)
>
> … where there is new information … brought out in the final decision by the regulator — if the asset owner doesn't have the ability to present new information [to the merits appeal body] to counter that, they're at a disadvantage. (AGL, trans., p. 782)
>
> [The further final decision] allows the service provider to put before the regulator at that point any information that the service provider might think is relevant should he wish to take the matter to a merits appeal. (ERA, trans., p. 987)

In addition, the Office of the Code Registrar noted there could be a lack of feedback to service providers:

> It could also lead to a long period of 'suspense' on the part of the service provider, if the regulator were not to be required to further consult with the service provider on the access arrangement. The absence of 'feedback' from the service provider during the formulation of the access arrangement could result in the insertion of inflexible or unworkable provisions into it. (sub. DR103, p. 3)

The Commission acknowledges that the further final decision might provide some benefits in the form of clarification and flexibility to attend to non-substantive elements of the final decision. However, this must be weighed against the costs of delaying the approval, when the service provider has already had two opportunities to propose an access arrangement that meets the requirements of the Gas Code. It seems, prima facie, that the further final decision adds unnecessary delay without delivering much benefit.

With regards to errors of finding or fact in the final decision, the Commission notes that there is currently scope to fix these in a number of ways. First, there is a draft decision to pick up such errors. If the errors are not discovered until the final decision, the service provider could ask the regulator to issue an erratum (as the ERA did for the Dampier–Bunbury pipeline access arrangement) (ERA 2004b). There is also a merits review for access arrangements drafted and approved by the regulator (section 11.2). As a last resort, there are provisions in the Gas Code for the service provider to initiate a review of the access arrangement (s.2.28). The Commission is therefore not convinced that the further final decision should be retained to deal with errors of fact in the final decision. The Commission notes that informal feedback mechanisms could help to overcome these problems and contribute to better decision making. For example, prior to the final decision, the regulator could give the service provider several days to verify that the data in the access arrangement are factually correct.

The Commission acknowledges the concerns of some service providers about the interaction of the further final decision with material that can be introduced at a merits appeal. The Commission discusses this in section 11.2, but notes here that the appellant has the opportunity to set out its reasons for review when initiating a merits appeal.

The Commission also notes the implication of the GasNet decision (the propose–respond model, rather than the propose–propose model). The Commission notes (chapter 7) that under this approach, there might be less need for a discussion over the non-substantive elements of an access arrangement, as the regulator will be able to discharge its duties under the Gas Access Regime without requiring amendments to non-substantive elements of the access arrangement.

In summary, the Commission is not convinced of the need for three rounds of decision making to approve an access arrangement. Thus, when the regulator makes a final decision, it should not specify amendments which would have to be made in order for the relevant regulator to approve the access arrangement. Rather, it should issue a final decision that:

- if the relevant regulator is satisfied the revised access arrangement incorporates the amendments specified in its draft decision, or substantially incorporates the amendments specified in the draft decision, or otherwise addresses the relevant regulator's satisfaction, approves the revised access arrangement
- in any other case, does not approve the revised access arrangement, and drafts and approves an access arrangement.

RECOMMENDATION 11.2

The Gas Access Regime should be amended whereby the 'further final decision' should be removed from the approval process for access arrangements.

Limiting amendments to access arrangements

Another possible area of improvement in the approval of access arrangements relates to the ability of service providers to propose amendments to their access arrangements up until the time the final decision is made. Section 2.15A of the Gas Code does not give the regulator power to specify a date by which the service provider may submit a revised access arrangement. The ACCC suggested changes to s.2.15A would lead to more timely outcomes:

…. the ACCC believes that additional restrictions on the ability of service providers and regulators to make new amendments late in the process will also significantly reduce the approval process timeframes. (sub. 48, p. 83)

… the ACCC proposes that the service provider be given a single, clear opportunity to submit amendments in response to the draft decision. Once this is done, the relevant regulator can then undertake a further round of consultation with interested persons seeking comments on both the draft decision and any proposed amendments by the service provider in response. (sub. 48, p. 84)

The Commission considers it is important to allow service providers to propose amendments to their access arrangements after a draft decision. Because many of the components of an access arrangement are interdependent, service providers must be able to amend the whole access arrangement in response to the regulator's decision. This might involve extra work for the regulator — for example, where the service provider significantly changes its access arrangement between the draft and final decisions — but the costs of not allowing amendments are likely to outweigh the costs of the extra workload of the regulator.

In relation to the timing of amendments, the service provider should be required to submit a revised access arrangement, incorporating all amendments, by a certain date. The regulator would then conduct public consultation and issue a final decision on the basis of the revised access arrangement. This approach should lead to more timely outcomes.

There was support for this recommendation. For example, the ERA noted:

… the secretariat supports this proposal and thinks it was a deficiency in the [Gas] Code that this wasn't available from day one. (trans., p. 987)

AGL considered that 'there should be provision for further amendments (including submissions) if there is a material change in circumstances' (sub. DR84, p. 43). The Commission acknowledges this concern. However, it notes that there could be difficulties in determining what satisfies a 'material' change. Also, there needs to be some finality to the process. The service provider, in any case, would have a right to respond during the public consultation process to submissions made by interested parties.

RECOMMENDATION 11.3

The Gas Access Regime should be amended so regulators can specify a date by which the service provider must submit proposed amendments to an access arrangement.

11.2 Appeal arrangements

The Gas Access Regime has two types of appeal: judicial review and merits review. Under the Gas Pipelines Access Law (GPAL), a judicial review is available for proceedings seeking civil penalties, damages, injunctions or declarations in relation to alleged breaches of the Gas Code. Each State and Territory has judicial review laws that apply to a judicial review under the GPAL.

Initially, the GPAL was drafted to allow proceedings to be brought in either the Federal Court or the State and Territory supreme courts. However, following the Re Wakim decision[1], which found that conferral by the States of jurisdiction on the Federal Court was invalid, proceedings must commence in the supreme court of the relevant State or Territory.

A merits (or administrative) review is a process that has been described as 'stepping in the shoes' of government decision makers and determining what is the 'correct and preferable decision' (ARC 1999, paras 1.1–1.2). Merits reviews are usually undertaken by a review tribunal.

Under the Gas Access Regime, the merits appeal is heard by the body specified as the local appeals body in each jurisdiction's gas pipelines access act. The Gas Code specifies four situations in which a merits review is available:

- ministerial decisions on coverage and revocation of coverage (ss1.19 and 1.39)
- access arrangements drafted and approved by the regulator after a final decision to reject an access arrangement submitted by the service providers (ss2.26 and 2.48)
- ring fencing decisions by the regulator with respect to waiving requirements or imposing additional requirements (ss4.11 and 4.24)
- decisions by the regulator with respect to the approval of associate contracts (s.7.6).

Part 6 of schedule 1 of the GPAL sets out processes and procedures to be followed for a merits review. This part of the Act comprises two sections:

- Section 38 provides for a merits review of decisions made in relation to: coverage and revocation of coverage; ring fencing (waiving or imposing additional obligations); associate contracts; and any other merits review specified in the Gas Code. To apply for review of a decision under this section, the applicant must be adversely affected by the decision.

1 *Re Wakim; Ex parte McNally; Re Wakim; Ex parte Darvall; Re Brown; Ex parte Amann; Spi* [1999] HCA 27.

- Section 39 provides for a merits review of decisions to approve an access arrangement which the regulator drafted after the further final decision. To apply for review of a decision under this section, the applicant must be either the service provider or a person adversely affected by the decision who made a submission during the regulator's initial decision making.[2]

Sections 38 and 39 also set out other requirements of, and limitations on, the appeal process — for example, who can apply and when, what information can be submitted by the applicant, what information the appeal body can use to make a decision, and the powers of the appeal body to make a decision. Some of these provisions are listed only in s.38 (and apply to both ss38 and 39); others are listed for decisions under s.39 only (box 11.2).

In effect, s.39 of the GPAL provides for a limited merits review of access arrangement decisions. The scope of such reviews is limited by the grounds of application, the information that can be included in the application, and the matters to which the appeal body can refer in making a decision.

Appeal processes are desirable for two reasons. First, the process of review provides an opportunity for decisions by Ministers and regulators to be scrutinised and challenged. Such a process might increase awareness among decision makers about the exercise of decision making power, within the terms of authorising legislation. It can promote the consistent application of the law by decision makers and lead to improvements in the quality of primary decision making.

As noted by BHP Billiton:

> 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 [Gas] 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 and consumers alike. (sub. 26, pp. 114–15)

Accountability is enhanced where the Minister and regulator are required to achieve clearly defined objectives and follow a transparent process, and their decisions are potentially subject to review.

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2 Section 38 could be interpreted to mean that decisions by the regulator to draft and approve an access arrangement would be covered by s.38 (even though s.39 explicitly provides for this). The Australian Competition Tribunal considered this matter in the recent case *Application by Epic Energy South Australia* [2002] ACompT 4. It decided that application for review of an access arrangement drafted and approved by the regulator is limited to an application for review under s.39.

Box 11.2 **Administrative appeals under part 6 of schedule 1 of the GPAL**

Provisions under s.38 (which apply to all merits reviews)

- An application for review must be made within 14 days of the primary decision being placed on the public register.
- The appeal body must make a decision in 90 days (with a 30 day extension available).
- Applications for review of decisions on access arrangements and associate contracts do not stay the decision. Applications for other reviews stay the decision.
- A decision made by the appeals body has the same effect as if made by the regulator or Minister. The appeals body may make a decision that:
  - affirms the decision made by the regulator or Minister
  - sets aside the decision
  - varies the decision.

Provisions under s.39 (which apply only to access arrangement merits reviews)

- The applicant must set out the details of the grounds for making an application.
- Applications cannot raise matters that were not considered by the initial decision maker and can be made on only three grounds [s.39(2)(a)]:
  - that there was an error in the regulator's finding of fact
  - that the exercise of the regulator's discretion was incorrect or unreasonable
  - that the occasion for exercising discretion did not arise.
- The appeal body can limit the scope of the appeal.
- In reviewing a decision, the appeal body must not consider any matter other than:
  - the application
  - the access arrangement and access arrangement information provided to the regulator
  - any reports relied on by the regulator to make the decision
  - any draft decision and submissions on the draft decision made to the regulator
  - the decision of the regulator and the written reasons for it
  - the transcript of any hearing conducted by the regulator.

Source: *Gas Pipelines Access (South Australia) Act 1997.*

Second, decisions made in the courts and tribunals contribute to a collection of case history, which can improve the predictability and clarity of interpretation. In discussing merits review provisions in the *Trade Practices Act 1974*, the Australian Pipeline Industry Association noted:

> Issues such as market definition and the identification of market power, the nature of public benefits and the relation between competition and efficiency, have all been clarified in crucial respects by Tribunal decision making. (sub. 44, p. 68)

The ACCC noted:

> A body of precedent is being established through court and Tribunal decisions and approval of access arrangements which will serve to assist industry and relevant stakeholders in understanding the operation and administration of the [Gas] Code. (sub. 48, p. x)

In considering the merits review more specifically, there are several reasons why it might be desirable to have a merits review in addition to a judicial review. First, a merits review is complementary to a judicial review. As the Administrative Review Council (ARC) noted:

> … the judicial review powers vested in the Federal Court are complementary to, but distinct from, merits review powers. Judicial review involves the exercise of the Commonwealth's judicial power and results in findings of law. Merits review involves the exercise of administrative powers and results in a correct and preferable decision. The different realms of operation of the two forms of review mean that they can, and often do, co-exist. (ARC 1999, para. 5.31)

Second, an administrative appeal is often a more feasible avenue than a court-based appeal. BHP Billiton commented that the complexity and costs of court-based appeals, given the diffuse nature of any potential benefits, make such appeals a relatively unattractive option for users and most other interested third parties (sub. 26, pp. 116–17).

Third, the Gas Access Regime creates legislative decision making powers for Ministers and regulators. Good administrative law practice sees benefits in having a merits review available whenever a legislative enactment creates a decision making power, especially where decision making bodies have discretionary powers (as is the case under the Gas Access Regime) (O'Connor 2000).

A decision made under the Gas Access Regime involves both procedural and judgemental elements. That is, when the correct procedures and processes are followed, the decision maker still exercises an element of judgment. There is a risk that an error will be made. The Kerr Committee noted that having a merits review available does not:

> … suggest that there is any propensity to err in the administrative process, although without doubt error does occur. It is the possibility of error that demonstrates the need for review. (Kerr Committee 1971, p. 3)

Finally, a merits review might be desirable for the Gas Access Regime, given the intrusion of access regimes on property rights and the freedom to contract. The

Hilmer Committee (1993, p. 242) noted that these are fundamental established rights in our legal system and are not to be disturbed lightly. It recognised that protection of these rights was an important concern:

> The Committee is conscious of the need to carefully limit the circumstances in which one business is required by law to make its facilities available to another. Failure to provide appropriate protection to owners of such facilities has the potential to undermine incentives for investment. (Hilmer Committee 1993, p. 248)

Protection of these property rights was the paramount concern in the Commission's consideration of appeal processes in its review of the national access regime report (PC 2001c). The protection of property rights was also the reason that a merits review was included in the Gas Code. The National Gas Pipelines Advisory Committee (NGPAC) noted that it was initially proposed during drafting of the Gas Code that there be no right to a merits review for decisions by the regulator on access arrangements:

> No appeal was provided for because it was thought that the relevant regulator was best equipped to make a decision in relation to an access arrangement and to avoid unnecessary delays in establishing a final access arrangement. (sub. 34, p. 48)

However, it noted 'service providers strenuously objected' to the absence a merits review, so:

> … section 39 was inserted to seek to balance the interests of service providers in having a right of recourse if an access arrangement was imposed by the relevant regulator, without, however, allowing unlimited appeal rights. (sub. 34, p. 48)

In a personal submission to the inquiry, Greg Harvey (Independent Chair of NGPAC) noted:

> … no fundamental property right of the asset owners was to be abrogated to the regulators' discretion without a right of appeal on the basis of merit/equity (as opposed to mere failure of defect in the administrative process). (sub. 15, p. 2)

Application of the arrangements

There has been some use of the appeal mechanisms in the Gas Access Regime. The merits reviews (by the Australian Competition Tribunal and Western Australian Gas Review Board) and the judicial appeals (by the Supreme Court of Western Australia) are listed in table 11.1.

Table 11.1 **Appeals under the Gas Access Regime**

Pipeline and appeal applicant	*Date of decision*	*Subject of dispute*
Australian Competition Tribunal		
Eastern Gas Pipeline — Duke Energy International	May 2001	Review of the Minister's decision on coverage
Wallumbilla–Rockhampton (Queensland Gas Pipeline) — Duke Energy International	May 2002	Review of the ACCC's decision to draft and approve and access arrangement for the Queensland Gas Pipeline
Moomba–Adelaide pipeline — Epic Energy	November 2002	Decision on a preliminary issue regarding the nature and extent of review available under ss38 and/or 39 of the GPAL
Moomba–Adelaide pipeline — Epic Energy	December 2003	Review of the reference tariffs in the access arrangement drafted by the ACCC for the Moomba–Adelaide pipeline and coverage of the Pelican Point expansion
Victorian transmission system — GasNet	December 2003	Review of the ACCC's decision to draft and approve an access arrangement for the Victorian transmission system
Moomba–Sydney pipeline — Orica, Endeavour Coal, Energy Users Association of Australia and Energy Action Group	Withdrawn	Review of the Minister's decision on revocation of coverage
Western Australian Gas Review Board		
Dampier–Bunbury pipeline Epic Energy, Western Power and North West Shelf Gas	Pending	Review of the access arrangement drafted and approved by the regulator
Supreme Court of Western Australia		
Dampier–Bunbury pipeline — Epic Energy	August 2003	Interpretation and application of the funding regulations in the GPAL
Dampier–Bunbury pipeline — Epic Energy	August 2002	Application of the reference tariff pricing principles in the regulator's draft decision
Goldfields Gas pipeline — Goldfields Gas Transmission	Withdrawn	Draft decision for the Goldfields Gas Pipeline access arrangement
Goldfields Gas Pipeline — WMC Resources	Pending	Interaction of the State Agreement and the regulator's draft decision under the Gas Access Regime

Sources: Australasian Legal Information Institute website; ACCC, sub. 48, p. 89; Epic Energy, sub. 37, pp. 45–6; Epic Energy 2004; Western Power 2004.

Inquiry participants' views on merits review arrangements

Many inquiry participants expressed concern about the operation of the current appeal arrangements and thought there was room for improvement. Considered here are the aspects of the current mechanisms where inquiry participants thought there is scope for improvement:

- who can appeal and when

- the timeliness of appeals
- outcomes of the appeal process
- grounds of appeal.

Who can appeal and when

Inquiry participants had two main concerns about who can appeal and when under s.39 of the GPAL:

- first, that the appeal arises after substantive elements of the decision have been made (AGA, sub. 13, p. 50; TXU Australia, sub. 11, p. 12) — that is, the appeal arises only when:
  - the regulator makes a further final decision not to approve an access arrangement and the regulator drafts an access arrangement (s.2.20)
  - the service provider fails to submit revisions or a proposed access arrangement to the regulator after the final decision, and the regulator drafts and approves an access arrangement (s.2.23)
- second, that users have no right to appeal if the regulator approves an access arrangement proposed by a service provider.

Regarding the first concern, the main consideration is whether the appeal right arises after the regulator's final decision or only after the regulator drafts and approves an access arrangement. It seems appropriate to have the right to appeal arise only after the access arrangement has been approved. Otherwise, it might be difficult for the party seeking a review to clearly define the grounds of appeal. It could be argued that given the regulator must give reasons for the final decision, it is possible that an appeal applicant could define the grounds of appeal based on those reasons. However, for practical reasons, the Commission considers the access arrangement would need to be approved for the appeal body to affirm, vary or set aside the decision of the primary decision maker.

The second concern was raised mainly by access seekers that perceived there to be an asymmetry in the appeal rights:

> 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. (BHP Billiton, sub. 26, p. 115)

The Commission agrees that there does seem to be an asymmetry in the appeal rights. Service providers will generally not seek a review of a decision if the regulator approves an access arrangement that they have proposed, but access seekers might be more likely to seek a review. Conversely, service providers might be more likely to seek a review where the regulator has drafted and approved an access arrangement, but access seekers are less likely to do so. The right to appeal arises only in the latter case.

This asymmetry in rights might provide asymmetrical incentives to the regulator when approving access arrangements. The regulator is less accountable for decisions in which it approves an access arrangement proposed by the service provider, because there is no merits review mechanism. In contrast, when the regulator does not approve an access arrangement, the regulator is more accountable for the decision through the merits review process.

As noted by BHP Billiton, this incentive system might bias the regulator in favour of service providers:

> 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. (sub. 26, p. 116)

The ARC guidelines on what decisions should be subject to a merits review noted:

> The Council prefers a broad approach to the identification of merits reviewable decisions. If an administrative decision is likely to have an effect on the interests of any person, in the absence of a good reason that decision should ordinarily be open to be reviewed on the merits.
>
> If a more restrictive approach is adopted, there is a risk of denying an opportunity for review to someone whose interests have been adversely affected by a decision. Further, there is a risk of losing the broader and beneficial effects that merits review is intended to have on the overall quality of government decision making. (ARC 1999, paras 2.4–2.5)

Timeliness of appeals

Another appeals issue raised by inquiry participants is the delays caused by appeals. Under the GPAL, delays are especially likely to occur for decisions made on coverage and ring fencing where initiating an appeal causes a stay on the decision. However, for access arrangement appeals under s.39 and associate contract appeals under s.38, initiating an appeal process is not a means of delaying the implementation of the decision.

As noted by Epic Energy:

> A service provider cannot frustrate access [through the use of the appeal provisions] because an access arrangement (the access arrangement drafted and approved by the regulator) is in effect during the period of the appeal process. (sub. 37, p. 46)

The ARC argued that the potential for large numbers of people to take advantage of the review, and the associated costs and delay, do not justify excluding those decisions from merits review. Rather, it argued 'there are other, preferable methods for containing the potential costs and delay of a high review rate' (ARC 1999, para. 5.29).

On the other hand, the ARC suggested that a merits review might not be appropriate where there has been a public consultation by the primary decision maker. It noted:

> If review of the subsequent decisions was undertaken, the nature of the review process would be changed from the normal adjudicative decision making process … to a greatly expanded and time-consuming one. (ARC 1999, para. 4.54)

The ACCC agreed with this limitation, noting that an extensive public inquiry process justifies:

> … the exclusion of merits review in relation to the relevant regulator's consideration of an access arrangement or revisions to an access arrangement. Deciding whether to accept an access arrangement requires the ACCC to investigate and consult widely with the parties who may be affected by the decision. The relevant regulator's decision has the potential to impact on a large number of people (for example producers, users and potential users). This process of consultation is interactive, in that it often involves the on-going exchange of information and views with affected persons over the course of the decision making process. A full merits review of such a decision (involving a re-determination of the relevant regulator's decision) would require a similar investigative process, rather than the adjudicative process typically used by a body such as the Australian Competition Tribunal. The cost and time involved in such a process would far exceed that usually involved in the conduct of a typical merits review. (sub. 48, p. 90)

However, under the Gas Access Regime, the merits review mechanisms currently available do not require the appeal body to undertake a fresh time consuming and costly public consultation. Rather, the review process operates where the appeal body considers material already submitted in the course of the public inquiries by the primary decision maker.

Outcomes

An effective merits review process would allow the appeals body to implement its findings, through the ability to clearly direct a remedying of deficiencies in the primary decision, or the substitution of its decision for those parts of the primary decision affected by errors. This is consistent with the ARC guidelines that the result of the merits review is the affirmation or variation of the original decision (ARC 1999, para. 1.2).

The possible outcomes of the appeal process are specified in GPAL under s.38(9) (box 11.2). The relevant appeals body makes a decision affirming, setting aside or varying the decision under review. The relevant appeals body is in a position to exercise the same powers and functions as the primary decision maker.

In the Eastern Gas Pipeline merits review, the Australian Competition Tribunal ordered that the decision of the Minister 'be set aside'. This meant setting aside the decision of the Minister to cover the pipeline (Australian Competition Tribunal 2001). The Australian Competition Tribunal affirmed the decision of the ACCC in the Queensland Gas Pipeline decision (Australian Competition Tribunal 2002b).

The AGA suggested that the possible outcomes of the merits review process need clarification:

> The AGA understands that it is not clear whether merits appeal under the current Gas Pipelines Access Law allows unconstrained re-arbitration of the initial decision. Provisions that clearly facilitate … the substitutability of the decision of a merits appeal body for that of the primary decision maker … should feature in appeal mechanisms under a revised Gas Access Regime. (sub. 13, p. 51)

In particular, the AGA recommended a reformulation where the primary decision can be affirmed in full, set aside to be remade by the primary decision maker, or varied according to findings of the merits review body. It would appear that the appeals body can affirm the decision in full or vary the decision. The Commission would be cautious about implementing the option to set aside the decision to be remade by the primary decision maker, as it fails to bring closure to the decision making process.

Grounds of appeal

Section 38 (relating to a merits review of a coverage decision) is not limited in relation to the grounds for review. However, the GPAL provides that an application under s.39 (relating to a merits review of an access arrangement drafted and approved by the regulator) may be made on the following grounds:

- that there was an error in the regulator's finding of fact
- that the exercise of the regulator's discretion was incorrect or unreasonable
- that the occasion for exercising discretion did not arise.

The Australian Competition Tribunal (2002a, para. 20) clarified that the nature and extent of a review under s.39, although involving a rehearing on the merits 'ought to be construed as one to be exercised for the correction of error'. It does not provide for a full merits review.

NGPAC noted this limitation is to 'avoid unnecessary delays in establishing a final access arrangement' and because 'it was thought that the relevant regulator was best equipped to make a decision' (sub. 34, p. 48). The ACCC similarly questioned the merits review mechanism given the time required for the conduct of these appeals (sub. 48, p. 89).

The South Australian Government noted the current limitations of s.39 were decided on 'after considerable discussion as part of the process for the establishment of the regime' (sub. DR108, p. 5). For this reason, it opposed any widening of the grounds of appeal.

There is a tradeoff between the scope of review available and the time and costs of conducting the merits review. WMC Resources commented that the current limitations strike the appropriate balance between seeking to limit the delay caused by a merits review of a decision and affording natural justice to persons aggrieved by a regulator's decision (sub. 43, pp. 25–6).

On the other hand, some inquiry participants thought the merits review should be extended. AGL commented:

> Normally, rights of review are available in relation to the process or procedure employed in arriving at a decision and in relation to the merits of the decision itself. (sub. 32, p. 18)

Alinta/Multinet noted that the limited merits review fails to adequately protect the private property rights of regulated companies (sub. 36, p. 15). It argued that this protection is especially important, given the intrusive nature of the current Gas Code.

> There is a clear need to incorporate more robust appeal arrangements into the [Gas] Code, to enable the owners of essential facilities to seek merit-based reviews of regulators' decisions. The strengthening of appeal arrangements would provide greater regulatory accountability, and more effective protection of the legitimate property rights of facility owners. We consider that delivery of effective appeal outcomes is an essential requirement if access regulation is to facilitate the maximisation of economic welfare over the longer term. (sub. 36, p. 1)

Similarly, Epic Energy and Australian Pipeline Trust commented:

> The need for a full merits review is imperative given the impact that regulation has on the viability of pipeline businesses. These businesses have made significant investments in Australia, yet their fate is presided over by economic theoreticians. (Epic Energy, sub. 37, p. 46)

> … [judicial and merits reviews] should not apply in a restricted manner, as is currently the case with reviews of decisions on access arrangements. The provision for merits reviews should incorporate unrestricted rights to a review of the merits of a regulatory decision. (Australian Pipeline Trust, sub. 55, p. 13)

It is not clear that Australian regulatory practice indicates a convention in favour of or against a full merits review. For aspects of the telecommunications access regime, a full merits review was available (for standard access obligations, access undertakings in relation to declared services and arbitration determinations). Recently, however, amendments to the telecommunications regulation have removed the right to a merits review of arbitration determinations. The Australian Government explained that the removal was due to significant delays in the review process (Explanatory Memorandum as quoted in ACCC 2003e, p. 64).

In the national access regime, there is a full merits review for a declaration decision and for arbitration outcomes. However, to date there has been only limited use of these provisions (PC 2001c). The National Electricity Code has a merits review for some decisions, such as authorisation of code changes and variation of the access undertaking, however, there is no merits review for revenue determinations. Some State and Territory regulators provide for a merits review (either full or limited) of any of their determinations under legislation (ACCC 2001c).

As discussed above, the purpose of a full merits review is to allow natural justice for those that might be adversely affected by a decision under the Gas Access Regime. The regime confers powers on regulators and Ministers that can intrude on property rights and the freedom to contract. Both the coverage and access arrangement decisions under the Gas Access Regime have the potential to affect the rights of service providers and others.

Material before the appeal body under s.39

One reason that the limited grounds could be removed is because other mechanisms in the Gas Code limit the scope of the appeal under s.39. The appeal body, for example, can consider only matters that went before the regulator, meaning an applicant cannot raise matters that were not considered by the initial decision maker and therefore cannot add new material.

While there was some uncertainty about the exact interpretation of the law on this point, the Australian Competition Tribunal decision in August 2003 on the Moomba–Adelaide pipeline provided some clarification:

> … the only matters, other than the Epic's application for review and submissions in support of it, to which this Tribunal may refer to are the matters specified in

> s.39(5)(a)–(f) inclusive which were available to the ACCC at the time of, or before, the decision under review was made. (Australian Competition Tribunal 2002a, para. 20)

Gordon and Edmonds-Wilson (2003) noted after the Australian Competition Tribunal's decision, that service providers should be very thorough in their submissions to the regulator:

> On every critical aspect of the submissions that a service provider makes to the regulator during the access arrangement (or revisions) approval process, the service provider should make detailed submissions supported, where that might be necessary, by expert reports. (Gordon and Edmonds-Wilson 2003, p. 1)

BHP Billiton considered the limitation on information before the appeal body to be a strength because it minimises the opportunity for parties to hold back 'important arguments from the regulator during the access arrangements revisions process' (sub. 26, p. 115). Service providers might hold back arguments if they consider they will achieve a better outcome from the appeal body.

Following the draft report, several service providers submitted that there should be a widening of the information that can go before the appeal body. For example, AGL noted:

> Restricting the material able to be put before the Tribunal proposal may prejudice service providers if they are unable to put material to the Tribunal to rebut material/findings of the regulator. This is particularly the case if the further final decision is removed; and there may be a material change in circumstances which is relevant. (sub. DR84, p. 44)

The Australian Pipeline Industry Association noted that 'a service provider has no incentive to withhold relevant information from a regulatory process'. It expressed concern that the regulator could surprise the service provider in the final decision. Without a further final decision, it argued the service provider is forced to 'undertake far more extensive preparation than would otherwise be the case'. It also expressed concern that without a further final decision, the regulator has the 'last word' (sub. DR100, p. 54).

The Commission notes, however, that for an access arrangement merits review, the appellant makes an application for review which sets out the reasons for review and therefore does have the opportunity to respond to the regulator's final decision, albeit without the support of additional material.

Material before the appeal body under s.38

In contrast to s.39, the scope of material considered in merits reviews under s.38 of the GPAL is unlimited. The NCC expressed some concern about the unlimited scope on the grounds that it:

> … gives parties the opportunity to engage in regulatory gaming, for example, putting material before the Tribunal which was not before the Council or Minister when the final recommendation and decision were made. (sub. 57, p. 53)

The NCC recommended curtailing the material available at a coverage review. That is, the full merits review currently available should be amended so the Australian Competition Tribunal has before it only material that went before the NCC and the Minister. Following the draft report, the NCC considered there would be merit in:

> … providing a limited exception for new material that is essential to a proper consideration of the coverage or revocation decision, but was not available at the time (as opposed to simply not supplied) the Council made its recommendations. (sub. DR92, p. 19)

The ACCC drew to the Commission's attention the possibility that restricting the material available at a merits appeal under s.38 to the material before the primary decision maker, might be interpreted as material that only went before the Minister making a coverage decision (sub. DR101, p. 58). The Commission considers, for the purpose of appeals on coverage decisions under s.38, that material before the primary decision maker (the Minister) should encompass material before the recommending body (the NCC).

The Commission's assessment

There is a need for a merits review under the Gas Access Regime. In the Commission's view, appropriate protection for property rights and natural justice are key considerations. While the appeal process might take considerable time and expend considerable resources, the regulatory bodies and Ministers have powers to make decisions that have an impact on fundamental rights of service providers. The prospect of exposure to imperfect regulatory instruments means there is a strong case for a merits review.

The purpose of the merits review is for the appeal body 'to step into the shoes' of the primary decision maker to determine if the decision was 'correct and preferable'. In keeping with this purpose, the Commission considers that it is appropriate to limit the material that can be put before the appeal body. Such a limitation currently exists for s.39 appeals (in relation to access arrangements drafted and approved by the regulator). However, no such limitation exists for s.38

(in relation to coverage decisions). The Commission considers the limitation should be maintained for s.39 and that s.38 should be amended to limit the material that can go before the appeals body to that which was before the primary decision maker.

Regarding the grounds for review, s.38 (for coverage decision merits reviews) is currently unlimited. However, merits reviews under s.39 (for access arrangements drafted and approved by the regulator), impose limitations on the grounds of appeal. The Commission considers there are good reasons for extending the grounds of appeal under s.39. That is, provisions in the merits review should not be confined to the grounds set out in s.39(2)(a) of the GPAL, but should allow scope for a full merits review. The Commission acknowledges the potential costs of widening merits review rights under s.39, but considers they will be mitigated, to some extent, by maintaining the limitations on material that can go before the appeal body.

Regarding the differences for who can appeal, s.38 (relating to review of coverage decisions), allows any party to appeal. However, under s.39, only service providers can appeal a decision to draft and approve an access arrangement. For coverage decisions, the Commission considers it is appropriate that any person can appeal. For access arrangements drafted and approved by the regulator, however, the Commission considers that it is appropriate for only service providers to have the right to appeal. This is because the regulatory intervention is on behalf of the wider economy, including users.

Regarding the outcomes of appeals under both ss38 and 39, the Commission is satisfied that the provisions in the GPAL allow the appeal body to 'step into the shoes' of government decision makers and affirm or remake administrative decisions according to the merits of individual cases.

RECOMMENDATION 11.4

Limitations on the grounds of appeal under s.39 of the Gas Pipelines Access Law should be removed to allow a full merits review on access arrangements drafted and approved by the regulator. This would be consistent with the grounds of merits review for coverage decisions.

RECOMMENDATION 11.5

The material that can be introduced to the appeal body for a merits review of a coverage decision under s.38 of the Gas Pipelines Access Law should be restricted to material that has already gone before the primary decision maker. This would be consistent with the merits review process for access arrangements drafted and approved by the regulator.

11.3 Funding arrangements

Several inquiry participants in Western Australia raised concern about the funding arrangements in that State. The Gas Pipelines Access (Western Australia) (Funding) Regulations 1999 (funding regulations) were introduced in January 2000 to provide for fees and charges in connection with the performance of the functions of OffGAR. The regulator is permitted to establish these regulations under ss86 and 87 of the GPAL (box 11.3).

Box 11.3 **Funding arrangements in Western Australia**

Section 86 of the GPAL allows the making of regulations, including those relating to fees and charges. Section 87 grants the power to make regulations for fees and charges in connection with the performance of the functions of the regulator.

The three types of financial impost under these regulations are:

1. fees for the provision of a specific service
2. a standing charge determined for each covered pipeline (payable quarterly)
3. a service charge levied in connection with 'doing anything' that is necessary and convenient to perform a function under the GPAL (such as consultancy expenses incurred by the regulator).

Sources: Clayton Utz 2003; Supreme Court of Western Australia 2003.

Epic Energy submitted that it has paid over $1.5 million in standing charges under the Gas Access Regime. In addition, it has incurred $1.3 million in regulator's 'consultancy fees, from lawyers to economists to engineers' for the Dampier–Bunbury pipeline access arrangement (sub. 37, p. 67). Epic Energy noted that such cost recovery is 'inequitable' (sub. 37, p. 44), expressing a preference for the costs of regulation to be 'borne from consolidated revenue'. It noted that if this does not occur, then a fairer outcome is one in which the costs of regulation are 'borne by the prime beneficiaries of regulation — the shippers and potential shippers' of gas on covered pipelines (sub. 37, p. 45).

The Chamber of Commerce and Industry of WA noted the funding arrangements are 'unfair' where:

> … a company is forced to bear the operational costs of an agency whose core requirements add to their costs and restrict their commercial freedom. (sub. 39, p. 3)

One issue in Western Australia has been OffGAR's commissioning of consultant reports. OffGAR noted that the complex and technical nature of the Gas Code means the regulatory process requires expert advice and considerable legal input (trans., pp. 80–1). Epic Energy noted that a lack of accountability might arise where the regulator can pass on the costs of the commissioned consultant reports:

> In the case of Western Australia, the fact that the regulator does not consider himself ultimately responsible for the costs the consults incur is problematic. (sub. 37, p. 38)
>
> In Western Australia … due to funding regulations, the regulator is not responsible for the costs incurred by the use of consultants because such costs are actually paid by the service provider. This creates … a lack of accountability in relation to the costs. (trans., p. 168)

The Supreme Court of Western Australia noted that the State's funding regulations require the regulator to provide, if requested, the person liable to pay a service charge with an itemised account of the costs covered by the charge. This requirement should improve accountability because the charges are transparent and open to scrutiny by the service provider (Supreme Court of Western Australia 2003, para. 49–50).

Some inquiry participants noted that service providers can pass the costs of regulation through to users and consumers via the reference tariff policy. The Queensland Competition Authority (QCA 2003a) approved applications for the pass-through of a levy charged to service providers for functions performed under the authority's Act.

Information provided by the Western Australian Government suggests the extent of the pass-through would be less than 1 cent per gigajoule (table 11.2).

Table 11.2 **OffGAR regulatory costs[a]**

Cents per gigajoule

	1999-2000	*2000-01*	*2001-02*	*2002-03*
Cost	0.66	0.64	0.55	0.70

a The responsibilities of OffGAR have now been assumed by the ERA.

Source: Western Australian Government, sub. 70, p. 8.

Some inquiry participants argued that the pass-through of costs does not always happen in practice. Goldfields Gas Transmission noted a 'practical inability to pass on regulator costs via a component of tariff charges' (sub. 18, p. 15). Alinta/Multinet commented that the regulator in Western Australia 'has proved reluctant to allow actual regulatory cost recovery in access arrangement mechanisms' (sub. DR91, p. 20). The Chamber of Commerce and Industry of WA noted that the ability to pass on costs depends on market conditions (sub. 39, p. 3).

Epic Energy advocated introducing a guaranteed pass-through of costs under the Gas Access Regime. It further argued:

> … [a] framework which does not guarantee the 'pass through' of regulator costs amounts to a 'stealth tax' imposed on regulated businesses. (sub. 37, p. 45)

Similarly, the ENA advocated that where a levy is imposed on regulated businesses:

> … there is a need to allow the passing through of any cost-recovery levy … to end users, given that a mandatory regulatory levy imposed on a service provider is by definition an unavoidable operating cost for the service provider. (sub. DR85, p. 32)

Alinta/Multinet further submitted that the regulator should set a fixed budget, which could be recovered from users. This would allow for 'the actual costs of regulation to be recovered via the access arrangement mechanism rather than forecasts' (sub. DR91, p. 21). It further noted:

> This would also provide a constraint on regulatory costs, as the regulator would need to take account of the impact on customers. (Alinta/Multinet, sub. DR91, p. 21)

Another important consideration raised by Epic Energy is that the recent decision of the Supreme Court of Western Australia held that costs recovered by the regulator should be 'reasonable':

> One of the declarations of the court was that the regulator may only impose service charges that pass on reasonable costs of a type which it was reasonably necessary or convenient for the regulator to incur. (trans., p. 168)

Epic Energy noted the benefits that might flow from this decision:

> This will require the regulator to not only be more circumspect about what costs he can pass on to pipeline owners but also what information he provides to justify these costs. … This should require the regulator to be more transparent and accountable in relation to costs he seeks to pass on. (sub. 37, p. 76)

In addition to consultant fees, other costs that raise concern are the legal costs incurred in judicial proceedings. This concern arose in relation to OffGAR's attempts to recover the legal costs from Epic Energy incurred during litigation over the draft decision on the Dampier–Bunbury pipeline access arrangement. Epic Energy refused to pay these costs:

> Epic Energy … persistently refused to pay at least [the regulator's] costs related to … participation in any challenges that stemmed from [the access arrangement] assessment process. The budget for these costs [was] approximately $800 000. (sub. 37, p. 76)

CMS Energy asserted that Epic Energy should be allowed to recover the costs of its legal action from the regulator (if it wins the action), along with the regulator's costs of preparing a 'flawed' draft decision. Epic Energy would thus pay only the costs that it incurred in preparing the valid draft decision (sub. 19, p. 48).

The ENA noted:

> … it is critical to avoid the perverse incentives that are potentially created in having the costs of legal actions undertaken by the regulator funded through cost-recovery arrangements. This effectively leads to circumstances which a regulatory body faces no incentives to minimise the total level or scope of litigation undertaken. (sub. DR85, p. 32)

However, the recent Supreme Court of Western Australia case (Supreme Court of Western Australia 2003) clarified the interaction of the funding regulations and legal costs arising from a judicial review. Generally, judges have discretion to determine who bears the costs of court proceedings. The court noted that an Act can modify or oust this discretion, but must do so expressly. The court decided that the GPAL does not expressly provide for the recovery of court proceedings costs (Supreme Court of Western Australia 2003, paras 61 and 68). Epic Energy commented that the Supreme Court decision on funding regulations goes 'some way to dealing' with problems created by the funding regulations in Western Australia (trans., p. 168).

Several participants submitted that funding should be borne out of consolidated revenues:

> … due to the diffuse benefits of access pricing regulation to the community at large it is appropriate that funding for regulatory oversight is provided by direct allocation from consolidated revenues. The cost of administering access pricing regulation is incurred solely due to the benefits derived by the community as a whole, as no benefits are derived by the service provider through the negative impact of access regulation on the exercise of its private property rights. (ENA, sub. DR85, p. 32)

> … further attention should be given to funding from consolidated revenue … on the basis that if regulation benefits the whole economy then the most efficient way to recover those costs is via broad based taxation. (Alinta/Multinet, sub. DR91, p. 20)

The Commission's assessment

The Commission considers that the funding regulations in Western Australia might change the incentives facing the regulator. The Commission's *Cost Recovery by Government Agencies* inquiry report found cost recovery arrangements might create incentives that run counter to agency efficiency and encourage undesirable practices such as 'gold plating' and 'cost padding' (PC 2001a, pp. 96–7). In addition, regulators are less accountable for the costs incurred in carrying out their functions because they are sheltered from budgetary and parliamentary processes (PC 2001a, p. 97).

However, cost recovery arrangements can be designed to minimise these undesirable effects. Well designed cost recovery arrangements can complement agency efficiency by instilling cost consciousness in both the agency and users. They can encourage service providers to take a greater interest in the cost effectiveness of agency activities and to demand greater agency accountability (PC 2001a, p. 95).

There is evidence that funding arrangements in Western Australia have features of well designed cost recovery. The requirements that accounts be itemised (on request) and that costs be ‘reasonable’ place some checks and balances on the regulator’s fees and charges. In addition, the court’s decision that legal costs cannot be charged to the service provider adds an appropriate limitation on the extent of service charges. Without this decision, a problem could arise whereby a regulator is unsuccessful in court proceedings against a service provider and ordered to pay all legal costs by the court, only to charge them back to the service provider through the funding regulations.

Regarding the pass-through of fees and charges, the Commission is mindful of the possible effect on users and consumers. Reference tariffs might increase and the competitiveness of products to which gas is an input might be affected (PC 2001a, pp. 119–21). However, the Commission considers that such a mechanism is appropriate given the benefits that flow to users and consumers from the Gas Access Regime (chapter 4). The information provided by the Western Australian Government (table 11.2) also suggests the pass-through might be small relative to the price paid per gigajoule of gas. The Commission also considers there might be merit in requiring the regulator to work within a fixed budget to reduce the uncertainty associated with forecasting the costs of the regulatory body.

While the discussion of cost recovery in this section has concerned arrangements in Western Australia, the issue is not confined to that State. As mentioned earlier, regulators in other States and Territories impose fees and charges for the provision of services (as done by the Queensland Competition Authority and the NCC, for example). Further, this issue might take on greater national significance given the Ministerial Council on Energy’s proposed energy reform model (chapter 12), which suggests a national regulator be funded by an industry levy (MCE 2003a).

If the proposed energy reform model eventuates with funding by an industry levy, it would be subject to the Australian Government’s recent cost recovery policy. This policy aims to improve the transparency, consistency and accountability of cost recovery by Australian Government agencies. Agencies with significant cost recovery arrangements are required to undertake stakeholder consultation (Minchin 2002).

FINDING 11.2

The application of the Australian Government's cost recovery policy to the funding of a national regulator through an industry levy would bring rigour to the funding arrangements proposed by the Ministerial Council on Energy.

12 Institutional arrangements

Examined in this chapter are issues arising from and possible improvements to the institutional arrangements that govern decision making under the National Third Party Access Regime for Natural Gas Pipelines (the Gas Access Regime). The chapter also notes work underway by the Ministerial Council on Energy (MCE) to reform the institutional arrangements.

The issues to be addressed when considering ways of improving the institutional arrangements include the:

- allocation of decisions (about coverage, the form of regulation and the terms of access) among regulatory agencies
- role of Ministers in the regulatory process
- value of establishing a national energy regulator with responsibilities for the gas and electricity sectors
- process for changing the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code).

12.1 Existing institutions and arrangements

Government agencies have roles in coverage and access arrangement decisions, appeals and changes to the Gas Code. Ministers have the final decision on coverage and Code changes. The Gas Access Regime therefore involves regulation and Ministerial involvement at the national and State/Territory levels.

Coverage and access arrangements

The roles of the national and State/Territory regulatory agencies are described in chapter 3. In summary, the National Competition Council (NCC) assesses applications for pipelines to be covered by the Gas Access Regime and for coverage to be revoked, and makes recommendations to the relevant Minister, who then makes a decision.

Either the Australian Competition and Consumer Commission (ACCC) or the local State or Territory regulator approves or determines access arrangements. In the case of transmission pipelines, the ACCC or Economic Regulation Authority (for pipelines in Western Australia) is the responsible regulator. For distribution networks, the State regulator or the ACCC (in the Northern Territory) is the responsible regulator.

Appeals

Appeal arrangements are described in chapters 3 and 11, with the latter providing detailed information on appeal processes. Judicial appeals commence in the Supreme Court of the relevant State or Territory. Merits (or administrative) appeals against coverage decisions by Ministers or access arrangement decisions by the ACCC or a local regulator can be heard by the Australian Competition Tribunal, or a local State or Territory appeals agency.

Gas Code changes

The National Gas Pipelines Advisory Committee (NGPAC) is responsible for recommending to Ministers changes to the Gas Code. It was established under the 1997 intergovernmental Natural Gas Pipelines Access Agreement and comprises nominees of the Australian, State and Territory governments, and non-voting representatives of Australian, State and Territory regulators and industry groups. Clause 9.4 of the agreement sets out the following role and functions for NGPAC:

> (a) monitor, review and report on the operation of the Gas Pipelines Access Law (including the [Gas] Code)
>
> (b) provide advice to the Ministers on interpretation and administration of the Gas Pipelines Access Law (including the Code)
>
> (c) prepare information on the Gas Pipelines Access Law (including the Code) for general publication
>
> (d) make recommendations on amendments to the Gas Pipelines Access Law (including the Code) to Ministers. (COAG 1997)

NGPAC acts as a forum for raising and discussing issues affecting administration of the Gas Access Regime, and for initiating regime changes. The relevant Ministers in all the jurisdictions must agree to all changes.

12.2 Effectiveness of the current arrangements

The ACCC enunciated a fundamental principle for institutional arrangements as follows:

> Effective institutional arrangements are underpinned by appropriate governance mechanisms that separate regulatory, policy and ownership responsibilities amongst different groups rather than combining any two of these within one entity. In addition regulators should be independent from vested interests and take an economywide perspective in discharging their duties. In essence these form the appropriate benchmarks to assess various governance arrangements. (sub. 48, p. xv)

Goldfields Gas Transmission supported the principle of separating law making (a policy function) and the administration of the law (regulation):

> … it is not a good practice of governance for the police who administer the law to be the ones to make the laws — or in the case in hand for regulators to lead (or even strongly influence) the development of the objectives and scope of regulation. (sub. 18, pp. 29–30)

Similarly, the Australian Gas Light Company (AGL) commented that it:

> … values the principle that no one body should have powers to determine what rules should apply to particular services and then to administer the rules in respect of those services. Allowing one body to have this dual role is of concern to AGL. AGL also notes that the Ministerial Council on Energy, in its recent communiqué, announced that it was recommending to COAG [Council of Australian Governments] that two new statutory commissions be established; one with responsibility for rule making and market development and one with responsibility for market regulation. (sub. 32, p. 26)

Coverage

The current arrangements clearly distinguish between a decision on whether a pipeline is to be covered and decisions on access arrangements for covered pipelines. Coverage is a Ministerial decision, based on an assessment by the NCC, while decisions on and administration of access arrangements are the responsibility of the ACCC or State/Territory regulators.

This role differentiation is consistent with the principle of separating policy-type functions from administrative-type regulatory functions. The incentives of the NCC are not clouded by the prospect of having to implement and administer its own policy decision. If the same entity was responsible for both policy and administration, it is conceivable that decisions on policy could be inappropriately influenced by the administration experience. Similarly, there could be a contagion of administration decisions from a decision on coverage.

The Australian Gas Association (AGA) expressed this point as follows:

> Separate regulatory bodies should determine coverage and access pricing matters, to prevent any regulatory authority from effectively determining the scope of its own jurisdiction. (sub. 13, p. 96)

The current coverage process, involving the NCC making a recommendation to the Minister, is consistent with the Productivity Commission's finding in its review of part IIIA of the *Trade Practices Act 1974* (the TPA) that Ministers should retain responsibility for the 'declaration' of essential infrastructure services (PC 2001c, p. 377). The process of the NCC advising on, and a Minister making, the final decision on coverage, however, creates uncertainty among the interested parties because of different approaches followed by different Ministers. The process also has consequences for the timeliness of decisions (chapter 11) and the amount of resources employed. The NCC noted:

> … there has been a considerable divergence of approaches adopted by different Ministers. For example, while the Gas Code requires the Minister to be satisfied of each of the criterion established for coverage (or revocation) under the Gas Code, there appears to be different levels of consideration adopted by different Ministers … Some Ministers appear to be satisfied provided the Minister is satisfied that the Council has followed proper processes and considered all submissions before it. Other Ministers prefer to consider the issues themselves in great detail in order to be satisfied. Some Ministers appear to accept submissions and material that was not before the Council, while other Ministers appear only to consider the information before the Council at the time it made its recommendation.
>
> This lack of uniformity in approaches being taken by Ministers means that parties dealing with the relevant Ministers often have little or no understanding of how the Minister will approach the issue. This may result in considerable uncertainty amongst interested parties and significant delay.
>
> The Minister performs precisely the same role as the Council. Sections 1.14 and 1.35 of the Gas Code give the relevant Minister power to require the Council to provide such information, reports and other assistance as the relevant Minister considers appropriate for the purpose of considering the application. The Council questions the benefits of such duplication of process, particularly in light of the delays that can arise. (sub. 57, pp. 52–3)

The Minister's decision on the application for revocation of sections of the Moomba–Sydney pipeline system, released on 20 November 2003 with a statement of reasons, is an example of a detailed consideration of the NCC recommendation (Macfarlane 2003a). The Minister came to a conclusion that differed from that of the NCC for one of the pipeline sections, based on a difference in interpretation rather than on the basis of new material.

Access

There are seven State and Territory regulators of access arrangements for gas pipelines, in addition to the ACCC (chapter 3). This relatively large number of regulators might reduce consistency in the application of the access arrangements. It might also make it more complicated for service providers operating in more than one jurisdiction, who thus need to communicate with more than one regulator.

Envestra, which operates gas distribution networks in Victoria, South Australia, Queensland, New South Wales and the Northern Territory, commented on the problems of having a number of regulators, but also recognised some benefits:

> It is evident by the different outcomes of different regulators applying the same [Gas] Code that consistency of regulation will never be achieved while State regulators exist. While there are benefits in maintaining State regulators (development of a diversity of regulatory approaches, stimulation of debate etc.), there is evidence through the final decisions delivered to date that regulators use regulatory precedent selectively. The tendency for regulation to feed upon itself has obvious shortcomings. A particular flaw is that regulators have tended to selectively adopt elements of other regulator's decisions, regardless of their appropriateness to market circumstances, or compelling evidence that these precedents were themselves correct. (sub. 22, p. 46)

BHP Billiton favoured a national regulator, noting:

> … the differing capacity and propensity of regulators to do the job that is entrusted to them under the [Gas] 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. (sub. 26, p. 124)

Australian, State and Territory regulators of gas and other utilities are members of the Utility Regulators Forum established in recognition of the benefits of cooperation and an integrated and consistent approach to regulation. The regulators meet quarterly to discuss issues of common interest. The Forum aims to:

- foster understanding of issues and concepts faced by regulators of similar industries
- minimise overlap of regulations for large users who operate across jurisdictions
- provide a means of exchanging information
- enhance the prospects for consistency in the application of regulatory functions. (ACCC 2003f)

Appeals

Maintenance of the availability of the judicial process on questions of law is an essential part of ensuring decision making power is exercised consistently and according to legal principle. Five of the six merits appeals since the commencement of the Gas Access Regime have been heard by the Australian Competition Tribunal (chapter 11). The sixth is currently being heard by the Western Australian Gas Review Board. Although local appeals bodies could be activated in most States, continuing to have most merits reviews heard by the Australian Competition Tribunal is cost-effective and more likely to produce consistent outcomes.

Gas Code changes

NGPAC is the forum for identifying the need for and initiating adjustments to the Gas Code. When the Gas Access Regime was established, the infrastructure and market structures of the gas industry were recognised as likely to grow in unforeseeable ways from situations that varied widely across States and Territories. Greg Harvey, independent Chair of NGPAC, noted (in a personal submission) that the Gas Access Regime needed to be flexible enough to respond to practical situations in the marketplace as they arose, rather than anticipate and regulate for them in advance (sub. 15, p. 3).

In commenting on the operation of NGPAC, Mr Harvey explained that there had been difficulties with change processes and conflict among the different interest groups represented on the committee:

> NGPAC voting members (i.e. jurisdictions) have shown a reluctance to pursue solutions to perceived regime inadequacies through the prescribed vertical chain of stakeholder consultation, NCC comment, NGPAC recommendation, through to ministerial endorsement and often legislative amendment. The source of this discomfort seems to have been based both on: (a) the process formally requiring a recommendation from NGPAC (with its nongovernment as well as government members) before any Minister or jurisdiction could amend the [Gas] Code; and (b) the inclusion among the membership of NGPAC of the regulators, in particular, who would administer any such changes.
>
> In this context it should also be added that, over time, the inherent internal conflicts of interest among NGPAC members have not been resolved, and in some cases have blossomed. Infrastructure and market development needs still differ among the various jurisdictions and nongovernment stakeholder representation has become more complicated. For example, when the [Gas] Code was being negotiated, there was very little opportunity for direct competition among and between transmission and distribution service provider member organisations such as AGA [Australian Gas Association] and APIA [Australian Pipeline Industry Association]. This has changed. (sub. 15, p. 6)

The NGPAC secretariat acknowledged that it has undertaken relatively little activity in relation to its function of monitoring, reviewing and reporting on the operation of the Gas Code:

> In the early years, the emphasis was on leaving some time for implementation of the first round of access arrangements to see what issues might arise. As time went on and experience from implementation accumulated, NGPAC members have discussed a range of issues concerning the operation of the [Gas] Code at meetings. However, Code change proposals aside, NGPAC has undertaken little in the way of formal studies or research on the operation of the Code. (sub. 34, p. 8)

In response to criticisms of a lack of progress on major problems with the Gas Code, the NGPAC secretariat noted:

> NGPAC has put on hold a range of issues in recent years to be considered as part of a major review of the [Gas] Code. However, at no point has NGPAC been unwilling to proceed with consideration of any major issue raised by a stakeholder, where the stakeholder was willing to invest the time to properly articulate the issue and the proposed amendment. (sub. 34, pp. 15–16)

The Council of Australian Governments (COAG) Energy Market Review chaired by Warwick Parer (EMR 2002) noted that only a small number of Gas Code changes have been processed:

> The change processes for the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), and the associated National Gas Pipelines Advisory Committee (NGPAC), have not demonstrated the ability to cope with a significant number of changes.
>
> Despite the continuing criticism on the part of the gas industry of the operation of the Gas Code, the number of Code changes processed since commencement of the access framework is low, with almost all being the product of regulator suggestions. Many proposed changes have never moved forward.
>
> The evident lack of industry ownership of the process may be linked with present NGPAC arrangements under which only jurisdictional representatives are entitled to vote on whether proposed changes can go forward.
>
> The process under which Ministers must agree all Gas Code changes also has consequences for the responsiveness of the process for the industry and for timeliness. The [Energy Market Review] panel does not support continuation of this arrangement. (EMR 2002, pp. 76–7)

The NGPAC secretariat (sub. 34, p. 12) noted 15 amendments to the Gas Code and/or the Gas Pipelines Access Law (GPAL). These amendments have been contained in seven amending agreements. Most have been of a technical nature or a clarification of the intended operation of the Gas Code.

The NGPAC secretariat and BHP Billiton contended that the number of changes to the Gas Code is not necessarily a measure of how good or bad the change process is. BHP Billiton submitted that:

> … the relatively small number of changes to the [Gas] 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 … [In] relation to the proposed mechanical changes to the Code, the process has worked well … (sub. 26, p. 127)

A number of inquiry participants have pointed to flaws in the current processes for amending the Gas Code. A common complaint was that the process was slow, particularly when dealing with emerging problems or issues of substance. The Essential Services Commission (of Victoria) commented:

> … NGPAC has tended to take a long time to consider proposed [Gas] Code changes. Further, given the numerous stakeholders represented on the committee, NGPAC members have generally found it difficult to agree on proposed changes. This problem has hampered the ongoing effectiveness of the Code, particularly its ability to respond to emerging problems, issues and market developments. (sub. 51, p. 19)

BHP Billiton made similar observations:

> … the effectiveness of the current structures in achieving [Gas] 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 [changes] are associated with substantive 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. (sub. 26, p. 126)

The South Australian Government, which provides the NGPAC secretariat, noted that a delay in considering a proposed change to regulators' information collection powers was related to the uncertainty created by the Australian Government announcement in October 2000 that there would be a review of the Gas Access Regime. NGPAC agreed to defer the proposal to be considered as part of the Commission's review of the regime (sub. 58, p. 10).

An important issue is the composition of NGPAC, and the extent to which it is representative of the stakeholders. BHP Billiton expressed a positive view:

> The process of developing [Gas] Code change proposals presented to Ministers has formal involvement of all interested parties — governments, regulators, industry and customers … 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. (sub. 26, p. 125)

On the other hand, Epic Energy perceived the diversity of membership as a barrier to the effectiveness of the change process:

> The ineffectiveness of the [Gas] Code change process is also due to NGPAC's large and diverse membership representing jurisdictions, pipeliners, shippers and regulators. Given the purported independence of the regulators, making them administrators of policy, not policy makers, Epic Energy questions whether they should be involved in what is effectively a policy making process. There is a clear conflict of interest between the regulators' role in implementing the Code, and the role they play as a member of NGPAC in relation to amendments to the Code, even though that membership is non-voting in nature. (sub. 37, pp. 47–8)

The AGA, which had been active in NGPAC since its commencement in 1997, spelled out at least two deficiencies in the Gas Code change process that it regarded as serious:

> - inadequate opportunities for formal participation by owners of sunk capital investments impacted by the Gas Access Regime in National Gas Code amendment procedures and processes; and
> - an inappropriate role for regulatory authorities in the initiation of, and decision making in relation to, proposed amendments to the Code. (sub. 13, p. 88)

Regarding the lack of opportunities for industry participation, the AGA stated that it is inappropriate for industry representatives as NGPAC members not to have voting rights, given the potential impact of Gas Code amendments on their property rights. Regarding concern about the role for regulators in the process managed by NGPAC, the AGA considered that this role represents an:

> … inadequate separation between the functions of policy making (including rule setting) and the administration and application of policy frameworks (enforcement of rules). (sub. 13, p. 90)

According to the NGPAC secretariat, it was recognised when the Gas Code was established that the presence of industry and regulator representatives would be a source of experience for implementing the Gas Code, but also a source of conflict of interest, which is why their role is limited to non-voting membership. The ACCC also agreed with the current structure that limits voting rights to the jurisdictions, given that NGPAC is an advisory body with responsibility for making recommendations to governments on Gas Code amendments (sub. 67, p. 4).

In relation to the claims of regulator dominance, the NGPAC secretariat noted:

> Of the total 16 recommendations to Ministers for amendments, regulators have sponsored four. Service provider representatives have sponsored five and governments have sponsored seven. (sub. 34, p. 18)

Regarding Ministerial approval of changes recommended by NGPAC, the South Australian Government noted that the average time between NGPAC recommendations and Ministerial approvals is two to three months. However, for certain changes to core provisions of the Gas Code, the requirement for unanimous approval by Ministers has led to delays (sub. 58, p. 11).

12.3 Improving the institutional arrangements

There has been significant progress in developing a reform program for the energy sector covering electricity and gas. The COAG Energy Market Review has reported on the strategic direction of energy reform and the MCE is well advanced in responding to the review and making decisions on new institutional arrangements.

This section outlines the key developments, and has findings and recommendations relating to the way in which gas would fit into the broader energy reform program. A central principle for the design of the institutional arrangements for the Gas Access Regime is the distinction between policy and regulatory functions which has implications for the allocation of responsibilities among government agencies and decision makers.

COAG Energy Market Review

The COAG Energy Market Review panel found serious deficiencies in the energy market, including confused governance arrangements, excessive regulation and perceived conflict of interest (EMR 2002, p. 9).

The COAG Energy Market Review found there are too many regulators:

> The multiplicity of regulators creates a barrier to competitive interstate trade and adds costs to the energy sector. The present arrangements are inappropriate for a situation in which cross-border energy flows are now a reality.
>
> Submissions to the review indicated significant industry disquiet about the present regulatory burden on energy businesses from national and local regulators, in particular different compliance requirements and the need to develop separate customer management systems for each State and Territory to address different regulatory requirements. (EMR 2002, pp. 74–5)

It found that the change processes for both the National Electricity Code and the Gas Code are deficient. Its criticisms of the Gas Code change process managed by NGPAC, including the small number of changes processed, are outlined above. The process for changing the National Electricity Code was described as complex and time consuming, involving cumbersome consultation and leading to uncertainty in the industry (EMR 2002, p. 76).

Additional problems for the existing governance arrangements in the electricity sector include the overlapping responsibilities of the National Electricity Market Management Company, the National Electricity Code Administrator, the State regulators and the ACCC and perceived conflict of interest where governments are owners, regulators and policy makers.

The COAG Energy Market Review reported that the role of governments in energy market governance is a serious unresolved issue, with ministerial decision making leading to uncertainty in both the natural gas and electricity sectors.

> Submissions [to the Energy Market Review] indicate that many stakeholders have a perception that governments' actions in the past have worked against confidence in the reform process and in energy markets more generally, creating uncertainty, instability and magnifying potential sovereign risk. This issue, like those discussed above, is long standing.
>
> Views among market participants vary widely, from those who want more ministerial involvement in market processes to those who argue for less. (EMR 2002, p. 79)

The South Australian Government's view on the role for government Ministers was representative of the views offered to the COAG Energy Market Review by many stakeholders:

> It is important for governments to provide a policy oversight role, while refraining from having any involvement at the operational level. (submission to the COAG Energy Market Review, quoted in EMR 2002, p. 80)

The COAG Energy Market Review recommended:

- an enhanced role for the MCE
- the establishment of a national energy regulator
- other changes to the governance and regulatory arrangements of the energy sector, including the Gas Code change arrangements (EMR 2002, p. 83).

COAG established the MCE in 2001 to provide policy leadership for the energy sector and to oversee the continued development of national energy policy. The Council comprises Ministers with responsibility for energy from the Australian Government and all States and Territories. The Australian Government Minister for Industry, Tourism and Resources chairs the Council (MCE 2004).

The MCE would be the ministerial decision-making body for Australia's energy policy, and have the responsibility to set in motion the considerable legislative change required to implement the reforms.

The benefits expected by the COAG Energy Market Review from a national energy regulator included greater regulatory consistency across the country, reductions in regulatory costs and improved incentives for energy businesses. These would be particularly relevant with increasing connectivity across state borders.

MCE reforms

In response to the COAG Energy Market Review, the MCE made the following proposals in August 2003 for improving the quality of economic regulation across energy markets:

- Two new statutory commissions be established on 1 July 2004, funded by an industry levy:
  - an Australian Energy Market Commission (AEMC) to be responsible for rule making and market development;
  - an Australian Energy Regulator (AER) to be responsible for market regulation.
- The new commissions initially be responsible for electricity wholesale and transmission in the connected (NEM [National Electricity Market]) jurisdictions, extended in 2005 to include gas transmission for all other than [Western Australia] (in accordance with the *COAG Natural Gas Pipeline Access Agreement of 1997*). Provision to be made for [Western Australia] and [Northern Territory] to join for electricity, and [Western Australia] for gas under the AER, by agreement. (MCE 2003b, p. 1)

The MCE report to COAG on 11 December 2003 reaffirmed and elaborated on these reforms (MCE 2003c).

The purpose of economic regulation of the energy sector was described in the MCE Report to COAG:

> The regulation of network access (prices and standards) seeks to balance energy users' short-term interests in price benefits with their long-term interests in a reliable supply, service enhancements and timely investment in new capacity. (MCE 2003c, p. 7)

The AEMC and AER will undertake economic regulation of the energy sector on a nationally uniform or consistent basis. Regulatory processes should be 'responsive to market developments, and occur within a clear framework of government policy' (MCE 2003c, p. 8).

A major responsibility for the MCE will be:

> … the introduction of an agreed national legislative framework for the Australian energy market, on a collaborative basis between Commonwealth, State and Territory Governments, pursuant to a new intergovernmental agreement between all jurisdictions (MCE 2003c, p. 7).

AEMC functions and membership

The MCE has defined the functions of the AEMC as follows:

> An Australian Energy Market Commission (AEMC) will be … accountable to and subject to the power of policy direction from the MCE. The core functions of the AEMC will include rule-making (code changes) and undertaking reviews, as directed by the MCE, including all code change and market development functions … (MCE 2003c, p. 8)

The AEMC will comprise three members, with two (including the Chair) appointed by the States, and the third by the Australian Government.

AER functions and membership

The AER will have responsibility for economic regulation under the agreed new national energy legislative framework. It will involve 'network access regulation and market rule enforcement' (MCE 2003c, p. 8). The AER will progressively take over energy regulation functions from the ACCC. In addition to the regulation of energy transmission, it will eventually 'be responsible for the regulation of distribution and retailing (other than retail pricing), following development of an agreed national framework' (MCE 2003c, p. 9). This means that it will take over some of the functions of State and Territory regulators.

The AER will comprise three members, with two appointed by the States, and the third from the ACCC. The Chair will be appointed by agreement of both the Australian Government and a majority of the States or Territories. The AER staff will be employed directly by the ACCC and then seconded to the AER (MCE Standing Committee of Officials 2004a, p. 4).

Division of responsibilities

Giving responsibility for managing rule making and code change to the AEMC rather than to the AER is in line with widely held views about the desirability of separating the rule making and administration functions. This approach is a significant divergence from the COAG Energy Market Review proposal, where the regulator was to have final decision making authority for pipeline coverage and Gas Code changes, as well as for the administration of access regulation.

Accountability of the AEMC to the MCE, which has the power to issue binding directions on and commission inquiries by the AEMC, also strengthens the separation of policy making from the implementation of policy.

FINDING 12.1

The Council of Australian Governments and the Ministerial Council on Energy are progressing the reform program for the energy sector. The governance arrangements involving the division of responsibilities and functions among the MCE, the Australian Energy Market Commission, and the Australian Energy Regulator apply the principle of the separation of policy development from the administration of policy.

Merits appeals

The MCE's proposed national approach could be expected to bring a national approach to the merits appeals processes of the Gas Access Regime. This would involve the Australian Competition Tribunal hearing appeals rather than the State or Territory appeals boards.

Comparisons of gas and electricity

As the gas market expands, it is becoming integrated into the total energy market. Gas is competing with electricity in the supply of energy to households and industries. It also provides another source of energy in the generation of electricity. As discussed in chapter 2, gas fired power stations have advantages in providing peak and some intermediate electricity capacity. VENCorp noted:

> It is clear that the reliability of electricity supply and the smooth operation of the National Electricity Market ('NEM') are increasingly dependent on gas fired power generation in the future. (sub. 23, p. 2)

A very important common feature of the gas and electricity markets is the reliance on fixed infrastructure of transmission and distribution networks, with a tendency for natural monopoly characteristics.

There are, however, important differences between gas and electricity relating to ownership and industry concentration, market size and maturity, market operations, and production and transportation technologies (box 12.1). These differences can have implications for regulatory arrangements, as noted by BHP Billiton:

> 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. (sub. 26, p. 124)

Box 12.1 Characteristics of gas and electricity markets

Some of the differences between electricity and gas are:

- extent of government ownership in transmission, distribution and production
  - electricity: government ownership remains widespread
  - gas: private ownership predominates
- extent of horizontal concentration of transmission and distribution within a region
  - electricity: highly concentrated
  - gas: quite high concentration in local distribution; less so in transmission
- market size and maturity
  - market size much larger for electricity than gas
  - electricity: ubiquitous supply to business and residential consumers
  - gas: large share of primary energy market in South Australia and Western Australia mainly for industrial and commercial use; widespread residential use in Victoria and ACT
- market operation
  - electricity: independent system operator of compulsory spot market across eastern states
  - gas: independent system operator only in Victoria
- energy production and generation
  - electricity: flexible primary energy source (fuel mix) and location of generation
  - gas: source determined by gas field location
- transportation technology
  - electricity: requirement for instantaneous balancing of supply and demand
  - gas: slow response to demand changes.

Differences in the operation of the electricity and gas markets are described in a report by ACIL Tasman (submitted to this inquiry by the ACCC):

> The electricity and gas markets in Australia differ significantly in form. The electricity market in the eastern states is characterised by a reasonably transparent, centralised, real-time, wholesale pool market. Western Australia is soon to develop a pool mechanism. Wholesale power is purchased by retailers and aggregators who hedge risk exposures through financial instruments. Transmission and distribution network usage is determined by the physics of electricity flow.
>
> The gas industry on the other hand operates without a centralised trading and price making market (with the exception of Victoria). Gas purchases continue to be mostly large long-term block trades, with upstream producers dealing almost exclusively with retailers and aggregators rather than end-users. Gas sales agreements are typically

> associated with ‘back-to-back’ transportation agreements with transmission and distribution owners. (sub. DR101, appendix H, p. 3)

The maturity, and interconnectedness of the electricity market in the eastern states of Australia favoured the development of a wholesale (gross pool) spot market for electricity managed by a central system operator, the National Electricity Market Management Company. The market rules are embedded in the National Electricity Code. The AEMC must seek authorisation of rule changes that raise competition issues from the ACCC under part VII of the TPA.

Bilateral contracting is the norm for the Australian gas market with no involvement of an independent system operator, in contrast to the National Electricity Market. For most of the Australian gas market, there is no requirement for ACCC authorisation of market rules under part VII of the TPA.

However, in Victoria, which has a more mature, dense and interconnected gas market than the rest of Australia, there is a limited wholesale (net pool) spot market operated by an independent system administrator (VENCorp). The spot market generates a market price for gas and facilitates the balancing of gas flows in the pipeline network. As noted by VENCorp:

> The Victorian wholesale gas spot market is fully integrated with the operation of the PTS [Principal Transmission System], with scheduling of the range of available gas injections to balance demand being determined on the basis of offers made in the spot market. (VENCorp 2003, p. 14)

VENCorp operates under Market and Systems Operations Rules authorised by the ACCC under part VII of the TPA. As with the National Electricity Market, the ACCC might be required to authorise rule changes that affect competition. A major review of the Victorian gas spot market pricing and balancing arrangements is nearing completion (see VENCorp, sub. DR106 for more information).

The integration of the electricity market in eastern Australia, together with the relatively high level of ownership concentration of transmission networks within states, might have contributed to the adoption of a part IIIA industry undertaking as the regulatory instrument for access regulation. Undertakings are voluntary and require approval and acceptance by the ACCC under part IIIA of the TPA. Undertakings do not require ministerial approval.

The pathway to regulatory coverage is different for gas. Applications for and decisions about coverage of gas pipelines are made on a case-by-case basis. Coverage of separate pipelines or networks is usually requested by access seekers and decisions are made by Ministers following recommendations of the NCC. This might reflect the more disaggregated private ownership and less mature development of the gas infrastructure.

The flexibility in the regulatory arrangements for gas being proposed by the Commission, with pipelines potentially able to be uncovered, subject to light-handed monitoring or subject to access arrangement with reference tariffs (regulation), reflect the variety of market circumstances that currently exist in the industry, and are likely to continue to exist for many years.

Perceptions of risk and factors affecting investment differ for electricity and gas because of differences in market characteristics, technology and regulatory arrangements. The regulation of the terms and conditions of access can have an important impact on risk and investment decisions and on the general effectiveness of the regulation.

FINDING 12.2

While there are some issues common to the electricity and gas supply sectors, there are significant differences, including in relation to market structure, size and maturity, market rules, nature of energy generation and transportation technology. These differences have implications for investment, risks and appropriate regulation.

Coverage and access arrangements for gas

One issue to address is whether the agency assessing coverage should also select the form of regulation to be implemented (assuming coverage is required). Whether to regulate and the form of regulation to apply are both policy decisions that require assessments of the scope for increased efficiency and thus the need for, and the intrusiveness of, regulation. The method of, and factors relevant to, making these assessments are similar. This similarity suggests that the same agency should make both assessments, which would be the NCC under current arrangements.

The market contexts might differ significantly for transmission pipelines and distribution networks, and for pipelines and networks in different locations. However, the same coverage criteria should apply (chapter 6).

Also, the considerations affecting judgments about the scope for increased efficiency resulting from intervention in the form of a monitoring regime or an access arrangement with reference tariffs form of regulation are similar for transmission pipelines and distribution networks. The expertise required for the assessments is similar across the range of markets involved. A single agency should bring consistency to the decision making process.

FINDING 12.3

Similar considerations are relevant for making decisions about coverage and the form of regulation. (These considerations also apply to both transmission and distribution infrastructure for natural gas.) The same agency should make recommendations on these issues.

Administering the regulation is a different function from deciding whether to regulate and what form of regulation to adopt, as discussed earlier. Having separate agencies to undertake the policy (review of coverage and form of regulation) and the administration functions is consistent with the Commission's view in its inquiries on the price regulation of airport services and the *Prices Surveillance Act 1983* (PC 2002b, 2001d). In reviewing the implications of price monitoring of airport services at the end of a predetermined period, the Commission noted:

> While the regulator is likely to have expertise in analysing monitoring information, as a matter of principle it would be desirable to separate policy and regulatory roles by having the review conducted by an independent body, as noted by the Commission in its review of the PS [Prices Surveillance] Act … (PC 2002b, p. 324)

The task of establishing and maintaining the information disclosure requirements for the monitoring regime being proposed by the Commission for the Gas Access Regime should be undertaken by a separate agency from the agency administering monitoring, as discussed in chapter 8. The agency developing the set of information disclosure guidelines could be the same agency that makes recommendations on coverage and the form of regulation.

FINDING 12.4

There are sound reasons for the agency responsible for developing the information disclosure guidelines, and updating them when the need arises, being separate from the agency administering the monitoring function.

The Commission's review of the Prices Surveillance Act referred to the conflict of interest that might exist if the regulator undertakes the policy and administration functions. It noted that evaluation of policy decisions about whether to regulate:

> … requires the assessment of the benefits and cost of regulation, which includes assessment of the regulator's likely performance in this regard. For this reason, combining the policy formulation and implementation functions is best avoided. (PC 2001d, p. 64)

RECOMMENDATION 12.1

The agency that recommends coverage of a pipeline, should also be responsible for recommending the form of regulation to apply to the pipeline.

RECOMMENDATION 12.2

The agency responsible for making recommendations on pipeline coverage and form of regulation decisions (currently the National Competition Council) should be separate from the regulator actually responsible for administering the regulation (either monitoring or access arrangements with a reference tariff).

Gas Code changes

Changing the working arrangements of NGPAC and raising the priority given to advising Ministers of strategic developments in the operation of the Gas Access Regime might address some current problems in pursuing changes to the Gas Code. Mr Greg Harvey commented along these lines:

> There is no impediment to NGPAC adopting procedures to establish, at the appropriate level of representation in each case, various working groups, under the auspices of the [Natural Gas Pipelines Access] Agreement and within the umbrella of NGPAC, to undertake the functions set out in clause 9.4.
>
> For example, a high level 'policy' advisory panel comprising only jurisdictions and industry representatives (overcoming the objection of including regulators in policy setting debate) could be formed to deal with matters referred to in ss9.4(a) and (b). A working group with a different level of individual membership could deal with [Gas] Code change proposals, taking policy guidance as appropriate on how to proceed and with what priority from the work of the policy panel. The composition and remit of such panels and working groups would need to be the subject of separate and detailed proposals to NGPAC from within its membership. (sub. 15, p. 8)

Sections 9.4(a) and (b) in the above quote are those parts of the COAG agreement (COAG 1997) that specify that NGPAC monitors the operation of the Gas Access Regime and advises Ministers on the regime administration. A benefit of the working group approach recommended by Mr Harvey could be a broadening of NGPAC's focus from Gas Code change proposals to these other functions.

Service providers perceive that the significant role of regulators in initiating amendments to the Gas Code undermines the separation of regulation policy making and administration. The COAG Energy Market Review's vision included provision for end users and the gas industry to have greater involvement in and ownership of the Gas Access Regime, but no provision for regulator initiated regime changes (EMR 2002, p. 97).

The Australian Pipeline Industry Association's position reflects service provider views:

> Effective separation of the [Gas] Code change and regulatory functions must be maintained (it is important to ensure that the role of the regulator is to implement the Code, not develop policy, and this requires a very clear and transparent 'separation of powers' between the regulatory and Code change functions — this lack of clarity and conflict represents one of our criticisms of the NGPAC process); and
>
> There should not be direct regulator participation or involvement in the Code change process. (sub. 44, p. 3)

The problem with NGPAC appears to be its operation as a single committee composed of three diverse groups (officials representing all the governments, industry representatives and regulators). There is a role for all three. Consultation with regulators and with industry representatives is essential because of their experience and knowledge of the industry. However, the Commission considers that the preferred approach is for policy advising to rest with government officials, with Ministers having ultimate responsibility for Gas Code changes. The principle of the institutional separation of policy making from administration would then be preserved.

As mentioned earlier, the MCE has delegated management of the Code change process to the AEMC. The MCE foreshadowed:

> … a more structured and transparent code change process to be followed by the AEMC, in which market participants, end users, the Australian Energy Regulator … and the Australian Competition and Consumer Commission (ACCC) will be involved. (MCE 2003c, p. 8)

The AEMC will not have the power to initiate code changes in its own right, except in limited circumstances (for minor or administrative changes).

An MCE Standing Committee of Officials has issued a discussion paper developing a model for managing the code change process based on the principles outlined by the MCE (MCE Standing Committee of Officials 2004b, pp. 1–2). The approach has six steps involving:

1. initial assessment of the code change proposal
2. informal feedback from the ACCC and AER on competition, access and regulatory issues
3. public submissions, working groups, a public forum and analysis by the AEMC
4. draft determination

5. second round submissions
6. final determination.

The MCE Standing Committee of Officials also noted that:

> On making its final determination, the AEMC will confer with the ACCC and the AEMC will decide whether to refer the code change proposal to the ACCC for authorisation or approval. (MCE Standing Committee of Officials 2004b, p. 14)

In step 3, it is proposed that the AEMC will seek stakeholders' views on whether the change is consistent with 'prescribed criteria', which relate mainly to the policy framework; the long-term interests of users; equality of treatment among market participants; equality between energy sources (gas and electricity); and equality between intrastate and interstate trade. The AEMC 'will undertake economic, legal or engineering analysis of a material code change proposal' (MCE Standing Committee of Officials 2004b, p. 11).

It is proposed that the final determination of the AEMC will include its assessment of the code change proposal against the prescribed criteria and report on the net benefits (step 6).

Such an approach would fulfil the obligation to consult with all the interested parties and achieve maximum stakeholder agreement. There is scope to 'fast track' the process, at the discretion of the AEMC, when the changes are minor.

Consultation with stakeholders about the process is continuing.

The MCE Standing Committee of Officials noted that:

> While the generic model for rule changes in this paper will apply to the NEC [National Electricity Code], it provides a general framework for code changes in respect of gas. The proposed code change process may be refined and adapted for gas, following consideration of outcomes of the Gas Access Regime review. (MCE Standing Committee of Officials 2004b, p. 3)

An area where the code change process for electricity could vary from that for gas might be in the extent of interaction of the AEMC with the ACCC and AER. This arises primarily because the National Electricity Market Access Code is a part IIIA undertaking, changes in which require approval and acceptance by the ACCC.

Also, changes to rules for the operation of a centralised wholesale commodity market, which might require ACCC authorisation, are an important issue for electricity, but not for gas except in Victoria.

For gas, the key requirement is that the Gas Code change process be managed and the recommendations or determinations be made by a body that is separate and independent from the regulator of the terms and conditions of access.

FINDING 12.5

The National Gas Pipelines Advisory Committee is not working effectively, and significant reform is necessary. The Ministerial Council on Energy's proposal for the Australian Energy Market Commission to be responsible for managing the code change processes would seem to address the concerns about NGPAC.

The role of Ministers

As discussed earlier, the NCC has concerns about the impact of ministerial involvement in the coverage decision. The NCC recommended removing the Minister from the process of determining whether a pipeline should be covered by the Gas Code:

> The Council therefore proposes that the Minister be removed from the coverage process. Rather, the Council proposes that the Council's final recommendation become the decision, which decision would continue to be reviewable by the Australian Competition Tribunal … (sub. 57, p. 53)

This change would shorten the time taken to reach a final coverage decision. However, this approach would be different to the general access regime contained in part IIIA of the TPA.

In its review of the national access regime, the Commission discussed the role and responsibility of Ministers in the 'declaration' of services following NCC recommendations. It noted that applying coverage criteria involves exercising substantial judgment. The Commission concluded:

> The exercise of such judgment will in turn involve tradeoffs between the need to provide appropriate protection for private property rights and wider efficiency and public interest considerations that might warrant regulatory intervention to facilitate third party access. The Commission concurs with the widely held view that such tradeoffs are generally more appropriately made by elected officials than by regulators. (PC 2001c, p. 376)

The preferred option is to retain ultimate Ministerial responsibility for the coverage decision.

Also in its review of the national access regime, the Commission contrasted the policy content of the coverage decision with the determination of access arrangements, which does not involve ministerial decision making:

> … the Commission accepts the validity of the broad division between high level coverage issues and the determination of detailed terms and conditions for access that underpins the current role for Ministers in part IIIA decision making. (PC 2001c, p. 376)

In regard to Gas Code changes, it appears that the MCE would delegate most determinations to the AEMC, which is accountable to the MCE. However, in its discussion paper on the code change process, the MCE Standing Committee of Officials noted:

> As an outworking of its market development responsibilities, the AEMC could of its own initiative, or at the request/direction of the MCE, develop proposed code changes to address a market development or MCE policy matter. The AEMC would make recommendations on such proposals to the MCE and it would be the responsibility of the MCE to initiate the code change proposal, not the AEMC. (MCE Standing Committee of Officials 2004b, p. 7)

The MCE Standing Committee of Officials referred to such a category of code change as:

> … code changes that affect protected provisions of the code, which will require the full code change process plus the sign-off from the MCE. (MCE Standing Committee of Officials 2004b, p. 10)

In the Commission’s view, it is appropriate that Ministers take direct responsibility for changes to the Gas Code that relate to government policy.

FINDING 12.6

Ultimate responsibility for decisions on pipeline coverage, the form of regulation and major changes to the Gas Code should continue to reside at the ministerial level. The Ministerial Council on Energy’s proposed framework for code change accommodates this approach. It appears that the MCE would delegate most determinations on code changes to the Australian Energy Market Commission (which is accountable to the MCE). However, some changes, including changes to MCE policy protected provisions of the Gas Code, require decision by the MCE.

Revised Gas Access Regime

The Commission has recommended significant changes to the Gas Access Regime. Included are some findings and recommendations that directly related to institutional arrangements. Overall, the Commission’s proposed Gas Access Regime, including the roles of Ministers and organisations, are consistent with the current proposals of the MCE.

FINDING 12.7

The reforms of the Gas Access Regime recommended by the Commission in this report would fit within the institutional arrangements developed by the Ministerial Council on Energy for a national approach to energy access regulation involving the Australian Energy Market Commission and the Australian Energy Regulator.