Coverage of the Eastern Gas Pipeline

A submission by DEI to the National Competition Council

Prepared by the Network Economics Consulting Group

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Contents

1 Introduction

AGL Energy Sales and Marketing Limited (AGL ES&M) submitted an application to the National Competition Council (NCC) for coverage of the Eastern Gas Pipeline (the EGP), which runs from Longford in Victoria to Horsley Park in Sydney, NSW under the *Gas Pipelines Access (Victoria) Act 1998, and Gas Pipelines Access (NSW) Act 1998*. The pipeline is jointly owned by Duke Eastern Gas Pipeline Pty Ltd, DEI Eastern Gas Pipeline Pty Ltd and is to be operated by Duke Australia Operations Pty Ltd (collectively known as 'DEI').

The NCC issued its Draft Recommendation[1] (draft recommendation) in May 2000. DEI and EAPL jointly commissioned the Network Economics Consulting Group to prepare this submission to the NCC relating to the application for coverage of the EGP and the NCC's draft recommendation.

1.1 Background

When fully utilised, the EGP is capable of delivering 110PJ per annum[2] of gas into the NSW and ACT gas market. The gas would derive from the Gippsland Basin. It has not yet commenced operation, but we understand that it is due to do so in September 2000. The EGP is not yet covered by any regulatory arrangements. However:

- on 18 November 1999, DEI supplied an undertaking to the Australian Competition and Consumer Commission (ACCC) which set out the terms and conditions on which DEI proposed to provide access to the transport and other services of the EGP. The Undertaking was submitted for approval under Part IIIA of the Trade Practices Act 1974; and

- on 7 January 2000, AGL ES&M submitted an application for coverage of EGP under *The National Third Party Access Code for Natural Gas Pipeline Systems* (the Gas Code).

The NCC and ACCC issued a joint press release relating to this issue on 21 January 2000.

The same gas market is also served by the EAPL Moomba Sydney pipeline (EAPL MSP) which transports gas from the Cooper Basin and which is seeking revocation of

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1 NCC May 2000. *Draft Recommendation Application for Coverage of Eastern Gas Pipeline (Longford to Sydney)*

2 When all planned compressors are operating.

coverage. We understand that the EAPL has a maximum feasible capacity of close to 290PJ per annum. EAPL MSP is covered by the Gas Code. However, we understand that:

- access arrangements for EAPL MSP have not yet been approved; and
- EAPL has submitted an application for revocation of coverage.

1.2 Purpose of the submission

In this paper we submit that the NCC should:

- agree that competitive neutrality between pipelines requires symmetrical regulatory arrangements with no period where there is some asymmetry;
- review the grounds for recommending coverage of EGP and continuing with the coverage of EAPL MSP, noting that in the medium term the grounds for coverage under the Code may be weak. In so doing it comments on the NCC's Draft Recommendations; and
- recognise that the risks of adverse outcomes from a medium term lack of coverage are small.

1.3 Structure of the submission

This submission is structured as follows:

- in section 2 we briefly review why EAPL MSP and EGP should both be subject to the same regulatory arrangements, and why to the extent possible the arrangements should be established at the same time;
- in section 4 we review whether the four criteria for coverage are met for EGP and EAPL MSP in the light of the NCC's Draft Recommendation; and
- the appendices review:
    - ➢ marginal costs of gas transmission; and
    - ➢ the impact of electricity prices on gas prices.

2 The NCC's Draft Recommendation

The NCC is required to recommend that the pipeline is covered if it satisfied that *all* of the criteria set out in section 1.9 of the Code are met:

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.

The draft recommendation reviews each of these criteria. The following comments are presented in the same order as that adopted in the NCC's draft recommendation.

2.1 Criterion (b)

The NCC considers that it would be uneconomic to develop a new pipeline to provide the relevant services provided by the EGP in any of the regions along the pipeline route. In reaching this conclusion the NCC has adopted the view that the relevant services are geographical (point-to-point) transmission services rather than the transmission services between the relevant markets in which competition might be promoted.

2.2 Criterion (a)

The NCC identifies that the relevant market in which competition may be promoted is the market for the sale of natural gas in SE Australia. It notes the existence of other relevant markets but has not been able to identify any in which criterion (a) might be satisfied. It then addresses whether competition would be promoted to a greater degree with coverage than without. The NCC is not able to satisfactorily answer this question in respect of the ACT and Sydney regions of the SE Australian gas sale market.

The NCC considers that EGP is likely to have market power in the gas sales market which would increase as excess transmission capacity is used up. The NCC also recognises that EGP may behave in a competitive manner, but lacks information on which to assess whether this might be so. It is therefore unable to clearly ascertain whether coverage would promote competition in the relevant market. Therefore, NCC sets out two options:

- a recommendation against coverage north of the ACT, but establishing arrangements to monitor competition in the gas market; or

- a recommendation for coverage.

The NCC is more definite in respect of regions south of ACT served solely by EGP, and considers that competition would be promoted in these areas.

Hence, although the NCC considers the relevant market for criterion (a) to be the SE Australian gas sales market, it clearly considers that there are also smaller and geographically distinct regions within that market.

2.3 Criterion (c)

The Council considers that increased access would not result in undue risk to human health and safety. We do not consider this issue.

2.4 Criterion (d)

The NCC considers that there is no public interest case for allowing DEI's Part IIIA Undertaking to proceed in preference to consideration of coverage under the Code, but recognises that there is a public interest case for regulatory symmetry.

3 Symmetry of regulation

This section of the submission briefly reviews the reasons for considering that different systems of regulation of pipelines serving the NSW and ACT gas markets would undermine competitive neutrality. Hence, we submit that neither EAPL MSP nor EGP should be covered by the Gas Code. In the next section we review the case for coverage.

3.1 Possibility of outcomes that do not best promote competition

There are two applications — for coverage and revocation of coverage — currently before the NCC. In our view, there is a risk that the two applications may be decided differently simply because they are separate applications which have been lodged at different times. Of the four possible permutations, two would be highly prejudicial to effective competition between the pipelines, namely:

- EGP is covered and EAPL MSP coverage is revoked; and
- EGP is not covered and the EAPL MSP revocation application is refused.

Either of these outcomes would diminish efficient competition between pipelines for the reason that the two competitors would be working under substantially different market rules, with large differences in the required level of information disclosure, different procedures for instituting price changes and responding to competitive pricing initiatives, and ultimately different regulatory philosophies.

It is also essential to ensure that there is minimum possible period of asymmetrical market rules, lest in that period one or other of the pipelines is required to release information or set prices that they would otherwise, under normal competitive operation, prefer not to do.

The NCC agreed that there was a public interest case for symmetry, but noted that symmetry did not require identical access arrangements (citing differences between arrangements for vertically integrated and stand-alone businesses). The Council also noted that the public interest case for symmetry might be satisfied by no coverage, but with the threat of some form of regulation, for example coverage in the future or Declaration.

While the Council presents this view, it does so in an ambiguous fashion. It is unclear whether it considers that:

- coverage of EAPL MSP and the threat of coverage on EGP would be symmetrical; or

- that symmetry requires that both EAPL MSP and EGP are not covered, but both face the threat of coverage in the future.

We would not consider that the requirement for symmetry would be satisfied by the former, not least because the two pipelines would face substantially different information disclosure requirements. The effect of this would be to make the prices offered by the covered pipeline less secret than the prices offered by the uncovered pipeline.[3] This would inevitably affect the relative competitive positions of the two pipeline operators.

[3] The importance of price secrecy is discussed in §4.2.

4 Application of the criteria to EGP

In this section we review whether the criteria for coverage are met for EGP and also for EAPL MSP. Our analysis focuses primarily on the first two criteria — whether coverage facilitates competition and whether EGP or EAPL are economic to duplicate. We do not review the third criteria related to health and safety. Finally, we review whether coverage would be in the public interest.

In the following analysis, we show that in the medium term it is uncertain whether coverage on EGP and EAPL MSP would satisfy the four criteria. Furthermore, we argue that delaying a decision on EGP coverage and revoking EAPL coverage does not present high risks of adverse outcomes because:

- the market circumstances mitigate against monopoly pricing;
- lack of coverage at this stage does not preclude some form of future regulation in the form of Declarations, voluntary Undertakings or a subsequent application for coverage under the Code. That is, there is a continued threat of regulation; and
- there are external constraints on pricing — most notably the maximum price of gas for electricity generation.

We first address the issue of whether the market circumstances are consistent with those that are likely to result in monopoly pricing and associated restrictions on access. We address this by reference to criterion (a) of the Code, whether access results in facilitation of competition in another market.

4.1 Facilitation of competition

In our view, criteria (a) of the Gas Code, that access (or increased access) should facilitate competition in an upstream or downstream market, requires:

- identification of whether coverage results in access or increased access;
- definition of the markets which may be affected by access; and
- determination of whether competition is facilitated in those markets as a result of access under the Code.

4.1.1 Access and access pricing

Assuming other criteria are satisfied the Code states that, if access to a pipeline promotes competition in another market, then the NCC must recommend coverage. This can be interpreted in one of two ways — either access (or increased access) *per se* or access (or increased access) resulting from coverage.

In our view, the latter interpretation should be adopted as the test is otherwise somewhat weak in character. Specifically, it would be satisfied by virtually all infrastructure based on technology exhibiting natural monopoly characteristics, and would have no regard to the actual access arrangements that might be in place. Furthermore, this position is supported by the NCC in its draft recommendation where it quotes from the Australian Competition Tribunal:

> *Rather, the Tribunal considers that the notion of "promoting" competition in s 44H(4)(a) involves the idea of creating the conditions or environment for improving competition from what it would be otherwise. That is to say, the opportunities and environment for competition given declaration,* ***will be better than they would be without declaration.*** *(emphasis added)*

In submitting that the test requires access or an increase in access as a result of coverage, it follows that the NCC would need to identify an appropriate counterfactual against which it could assess the impact of coverage.

The counterfactual

The Council discusses the selection of the counterfactual in its draft recommendation and, based on legal advice, notes that the appropriate counterfactual is the world in which EGP is not covered under the National Code *or* DEI's proposed Part IIIA Undertaking or Declaration. EGP is not yet operating, so the counterfactual is to a degree hypothetical.

The position adopted by the Council is sensible, but only if in positing market outcomes, the Council recognises the continued prospect of regulation in the absence of a coverage decision at this time. If the Council decides not to recommend coverage of EGP, this does not prevent coverage at some future time, and does not prevent Declaration or the ACCC from accepting an Undertaking. The NCC appears to accept that this view has some validity when it notes the effect of the "threat" of regulation in its draft recommendation:

> *it might be argued that, in some circumstances, no coverage under the National Code with the possibility (or threat) of coverage in the future is consistent with the principle of regulatory symmetry.*[4]

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[4] Noting our reservations on the symmetry argument in this statement, as discussed in §3.

In accordance with the discussion presented in section 2, we consider that the counterfactual should be based on symmetrical regulation of EGP and EAPL MSP, in which neither is covered by the National Code. However, this raises the important question concerning the characteristics of the market in this world, which must have regard to the likely commercial behaviour of the pipeline operators.

In our view, DEI's proposed Undertaking should provide some guidance to the Council on EGP's intended commercial behaviour, and hence on market outcomes. DEI would clearly prefer to operate under the terms of its proposed Undertaking than under the Code. Hence, if the NCC were not to recommend coverage at this point (in the absence of information that clearly suggests coverage is warranted) DEI would be unlikely to behave in a manner which subsequently precipitated coverage — for example, by deviating significantly from the terms of a proposed Undertaking.

Thus, while we recognise the legal view that the counterfactual should not be based on the EGP operating under a Part IIIA Undertaking, the terms in DEI's proposed Undertaking are relevant to assessing market behaviour in the absence of coverage once EGP commences operation.

4.2 Promotion of competition

To assess criteria (a), the first test is whether coverage of EGP, once in operation, results in increased access compared to no coverage. The second part of the test is whether this access would promote competition in another market. We first address whether coverage would increase access by examining:

- the supply and demand of transmission into the NSW/ACT market; and

- whether the market for pipeline services is such that, in the medium term, providers would have incentives restrict access.

For the purpose of this discussion, we initially accept NCC's view that the relevant market is the market for the sale of gas in SE Australia, but note that there are links between the gas and electricity markets such that electricity prices have a strong influence on gas pipeline tariffs. We return to this issue later in the submission.

4.2.1 Pipeline capacity and its impact on pricing behaviour

Supply and demand in ACT and NSW

Figure 4-1 shows expected demand for gas in NSW and ACT under two scenarios: a 3% annual growth in demand based on historic trends in demand for gas in NSW and ACT taken from the Australian Gas Association. The table also shows demand supplemented by the commissioning of 500MW of combined cycle gas turbine generation in 2003. These are compared with the availability of pipeline capacity. The pipeline capacities presented in the table do not require further compressor facilities, so the marginal cost of providing the incremental capacity is close to zero. Notwithstanding this, the marginal costs of expanding capacity above these levels is small in comparison with average pipeline costs; Appendix 0 presents some estimates of pipeline marginal costs.

The quantum of spare capacity shown in Figure 4-1 does not take into account seasonal variation in demand, which results in peak day demand in excess of average demand. There is some ability to manage this effect through linepacking but none the less peak capacity requirements are likely to be 25% higher than average capacity.[5]

Figure 4-1. Pipeline capacity and NSW/ACT gas demand

	2000	2001	2002	2003	2004	2005
EAPL MSP peak capacity (PJ/annum)	172	172	172	172	172	172
EGP peak capacity (PJ/annum)	55	55	55	55	55	55
EAPL MSP effective capacity (PJ/annu	138	138	138	138	138	138
EGP effective capacity (PJ/annum)	44	44	44	44	44	44
Expected demand (PJ/annum)	126	129	133	137	141	146
Spare capacity (PJ/annum)	56	52	49	45	40	36
500MW CCGT in 2003 (PJ/annum)	126	129	133	165	169	174
Spare capacity (PJ/annum)	56	52	49	17	12	8

There is considerable variation in gas demand forecasts. The 126PJ/annum figure for 2000 is derived from the NSW Ministry of Energy and Utilities 1999 *Energy in NSW 1999* using the 3% annual growth rate estimated from AGA data. However, in 1997 AGA itself forecast NSW/ACT gas demand of 148.3PJ in 2000, and the NIEIR forecast demand in excess of 130PJ/annum. ABARE forecast demand of 142.0 in 2000, which implies 7% annual growth rates since 1996, far above observed growth rates. This material is reviewed by the NCC in its draft recommendation.

EGP and EAPL MSP have, between them, sufficient installed capacity that is immediately available, with no capital expenditure to meet anticipated demand for gas transport services into NSW/ACT for at least five years, having regard to requirements to meet peak day demands. Furthermore, they have already contracted to provide access to pipeline capacity to a number of market participants, in the case of EGP without coverage arrangements under the Gas Code. Accordingly, it is clear that neither EGP nor EAPL MSP has any incentive to restrict access, particularly in the medium term.

5 This accords with the variation in Cooper Basin output between winter and summer months reported by the NCC in their draft recommendation.

Simple models of behaviour

Simple modelling of the likely behaviour of duopolists in these circumstances — Bertrand and Cournot competition — suggests equilibrium prices equal to marginal costs.

Bertrand competition, in which competitors choose their prices simultaneously and non-cooperatively, results in equilibrium prices equal to the marginal costs of the most expensive supplier. This is illustrated in Figure 4-2 which shows the Nash equilibria when each player follows a three part bidding strategy, $0.20/GJ, $0.30/GJ and $0.40/GJ. The model assumes that marginal costs for additional capacity are the mid-point of the estimates presented in Appendix 0. A single Nash equilibria arises in which the clearing price for the pipelines $0.20/GJ and both pipelines offer the same low price of $0.20/GJ.

Bertrand competition represents one extreme outcome of duopoly behaviour (prices equal to marginal costs).[6]

Cournot competition can be likened to the situation where firms choose their capacity, and an auctioneer then determines the market clearing price. If the initial price is assumed to be $0.71/GJ — EAPL's proposed Moomba to Wilton base-load price — and given the excess capacity shown in Figure 4-1, Cournot competition only results in transmission prices above marginal cost under high price elasticity of demand assumptions, and assuming that demand increases above trend levels with the addition of base-load gas fired generation. This is illustrated in Figure 4-3.

The basic Bertrand model assumes that there are no capacity constraints. When capacity constraints are considered, *capacity constrained* Bertrand competition gives rise to a large number of possible price equilibria, if one assumes that demand can freely switch from the pipeline with high prices to the pipeline with lower prices, within the limits set by the capacity constraints. Thus, given demand of 129PJ/annum and a maximum capacity on EGP of 55PJ/annum, clearly EAPL will be required to meet at least 74PJ/demand even it sets a price above the level set by EGP.

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[6] See Tirole, 1988 *The Theory of Industrial Organization* MIT for a detailed discussion.

Figure 4-2. Bertrand competition (2001 demand)

PJ demand			Low price ($0.20 / GJ)	Med price ($0.30 / GJ)	High price ($0.40 / GJ)
EGP bid	Low price ($0.20 / GJ)	EAPL	64.7	0.0	0.0
		EGP	64.7	129.4	129.4
	Med price ($0.30 / GJ)	EAPL	129.4	64.7	0.0
		EGP	0.0	64.7	129.4
	High price ($0.40 / GJ)	EAPL	129.4	129.4	64.7
		EGP	0.0	0.0	64.7

Operating profit ($m)			EAPL bid		
			Low price ($0.20 / GJ)	Med price ($0.30 / GJ)	High price ($0.40 / GJ)
EGP bid	Low price ($0.20 / GJ)	EAPL	9.7	0.0	0.0
		EGP	6.5	12.9	12.9
	Med price ($0.30 / GJ)	EAPL	19.4	16.2	0.0
		EGP	0.0	12.9	25.9
	High price ($0.40 / GJ)	EAPL	19.4	32.3	22.6
		EGP	0.0	0.0	19.4

The figure shows equilibrium outcomes under Bertrand competition in which each player can adopt three pricing strategies. The operating profit calculations assume marginal costs at the mid-point of those presented in Appendix 0. The simple example assumes there are no capacity constraints, and that the market is divided equally if the prices offered by the two pipelines are the same. The shaded area indicates a Nash equilibrium in which no player would wish to change price given the behaviour of the competitor.

However, in the current circumstances a substantial quantity of gas is under contract until 2002 (which, in effect, means that customers cannot switch between pipelines). Hence, it is doubtful whether more than 20PJ of demand currently met by EAPL would be free to switch in 2001 and 2002, in which case capacity constraints would not be binding and the outcome would be similar to non-constrained Bertrand competition.[7]

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[7] In effect, this assumes that each pipeline can handle all of the demand that is capable of switching between pipelines. In practice, there are constraints other than existing contracts, such as the processing capability at Longford, which complicate such a calculation. Note also that EGP will secure some 20 PJ / a of EAPL MSP's load through the transfer of supply from the Cooper Basin to the Gippsland Basin; this may well represent a significant proportion of the demand that can switch in the short term.

Figure 4-3. Pipeline prices under Cournot competition

	2001	2002	2003	2004	2005
Expected demand (PJ/annum)	129	133	137	141	146
Spare capacity (PJ/annum)	52	49	45	40	36
500MW CCGT in 2003 (PJ/annum)	129	133	165	169	174
Spare capacity (PJ/annum)	52	49	17	12	8
Transmission price ($/GJ, -0.1 elasticity	$0.17	$0.17	$0.17	$0.17	$0.17
Transmission price ($/GJ, -1.0 elasticity	$0.17	$0.17	$0.17	$0.17	$0.17
Transmission price ($/GJ, -0.1 elasticity	$0.17	$0.17	$0.17	$0.17	$0.17
Transmission price ($/GJ, -1.0 elasticity	$0.17	$0.17	$0.39	$0.47	$0.56

The model assumes a base transmission price of $0.71/GJ/annum and marginal transmission costs for the most expensive pipeline of $0.17/GJ/annum. The model was run using low and high price elasticity of demand figures of –0.1 and –1.0. These are broadly consistent with typical estimates of short and long-run elasticity estimates for gas.

Simple non-cooperative duopoly modelling would suggest that prices would be unlikely to rise substantially above marginal cost, particularly in the early stage of the market where the quantum of uncontracted demand is small. The corollary of these models is that pipeline owners would not restrict access. Restricting access would requires setting prices above marginal cost, or setting quantities at which the resultant clearing price is above marginal cost. Under non-cooperative duopoly behaviour, these would not represent equilibrium outcomes — one or other of the pipelines would be in a position to increase profits by removing the restrictions or reducing price.

Despite the considerations set out above, it is also clear that neither EGP or EAPL would be satisfied with prices equal to marginal costs, as this would not enable them to cover their fixed costs. The base-load tariffs required to cover costs would appear to be $0.71/GJ for EAPL MSP and $0.86/GJ for EGP over a one year period. Hence, one must examine whether there are prospects for tacit collusive equilibria at prices above marginal cost. If so, EGP and EAPL might have incentives to restrict access.

More complex models of behaviour and tacit collusion

In practice, duopolists interact with each other over a period of time. Repeated interaction upsets the outcomes observed with one-shot non-cooperative behaviour. This repeated interaction raises the prospect of maintaining prices above competitive levels through tacit collusion.

The *Folk Theorem* for infinitely repeated games predicts that players in repeated games, if sufficiently patient, will be able to reach an equilibrium which is Pareto optimal for them even though it would not be an equilibrium in a non-repeated game. That is, collusion can be sustained as an equilibrium when games are repeated. This form of tacit collusion is more likely to occur:

- when players can react quickly to punish behaviour;
- if it is easy to detect deviations in behaviour; and
- if players have the ability to coordinate punishments or there are fewer players.[8]

There are clearly features of the current market arrangements for gas which suggest that collusive outcomes are possible. Most obviously, there are only two pipelines so there are no difficulties coordinating punishment, and there are few players to examine for evidence of cheating.

However, it is also clear that there are a number of market characteristics which could mitigate against collusive outcomes:

- there is a large gap between average costs and marginal costs, so a punishment strategy in which one pipeline reduced its prices to marginal costs would be extremely costly for that pipeline. This suggests that such a punishment strategy lacks credibility;
- punishment strategies by the competing pipeline may take a substantial period before they become effective — for example, customers often buy transmission capacity on long-term contracts — raising the cost and reducing the credibility of punishment;
- in the absence of access rules that facilitate the dissemination of pipeline prices, prices may remain somewhat hidden — price secrecy mitigates against collusive outcomes. There are a number of factors which would contribute to this:
  - ➢ each pipeline would tend to deal with a small number of large and sophisticated customers — this tends to reduce price transparency;
  - ➢ those customers will negotiate both transport and molecule contracts — hence it would not always be obvious to a pipeline

8 Given the costly nature of punishment, some players might wish to leave punishments to others, which would then reduce the likelihood of reaching a collusive equilibrium. Hence, coordination of punishment (which is easier with fewer players) facilitates tacit collusion.

that any reduction in demand is a consequence of changes in a competing pipeline's prices; and

- gas transmission pricing has a number of different elements. There are several different transmission services involved, the contracts are generally for several years[9] and the structure of pricing (e.g. take-or-pay provisions) can have a significant impact on the customers' marginal costs — product heterogeneity reduces the risk of tacit collusion.

Hence, in recognising that there is a possibility of collusive outcomes, it is not self-evident that the characteristics of the market are such as to make this inevitable, or that coverage under the Gas Code would mitigate this risk. Indeed, it is quite possible that the imposition of coverage may facilitate collusive outcomes, where equilibrium prices remain close to reference tariffs with little or no discounting below that level. For example:

- coverage imposes substantial information disclosure requirements on the pipelines covering costs and prices, which would considerably enhance detection of 'cheating'; and

- the access regime may foster shorter term contracting behaviour by pipeline customers.[10] The incentives for competing pipelines to 'cheat' are reduced if the game is repeated more frequently.

The NCC, in its draft recommendation, dismisses concerns that coverage under the Code would facilitate tacit collusion, noting that:

> *However, it is not clear that the information disclosure requirements of the National Code are likely to damage competition in this way.*
>
> *First, the regulator (in this case the ACCC) has some discretion over the type of information that is released in conformity with the mandatory disclosure provisions governing pricing, cost and pipeline capacity information. If the ACCC considered that disclosure would be likely to lead to anti-competitive outcomes, it could exercise its discretion in the way in which this information requirement was met.*
>
> *Second, the minimum information required in the various pipeline management, services and trading policies is not high, and does not appear to be of a nature that would facilitate collusion between pipeline owners.*

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9 See the following discussion of contacts for gas transmission to power generators.

10 Because the Code has the effect of reducing transmission price and quantity risk, so reducing the benefits of long-term contracts which generally serve a similar function.

Third, the information disclosure provisions may facilitate greater scrutiny of prices thus making it is easier for the regulator and the market to detect collusion.

There are two substantial concerns with the position adopted by the Council. First, it is not clear that the discretion that the ACCC has in respect of information disclosure relates to disclosure that might harm competition. Specifically, while the ACCC has some discretion under 2.8 and 2.9 of the Code, this is directed at disclosure of data that is *not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User*. It is not clear that this then relates to disclosure that might harm competition, even if the ACCC were able to identify such behaviour.

Second, the literature makes clear that the risk of tacit collusion is reduced when there are detection lags. Detection lags are more likely to occur when prices are secret, and are therefore undermined by extensive information disclosure requirements. Absent regulation, there are a number of characteristics of the market that would tend to result in detection lags, as noted above. For example, there are relatively few customers for pipeline services,[11] they are generally large buyers and there is a tendency for long-term rather than short-term contracts. Indeed, it is recognised that duopolists often seek to remove price secrecy by, for example, retail price maintenance or formation of trade associations in which pricing information is collected and shared. Information disclosure under the Code is likely to obviate such action, which might otherwise be in breach of the Trade Practices Act.

The minimum information disclosure rules are set out in Attachment A of the Code. In our view they provide a great deal of information that would facilitate collusion. For example the combination of *tariff determination methodology, cost allocation approach, incentive structures* along with the extensive data on capital costs and operating costs should be sufficient for a well informed competitor to determine individual tariffs with a high degree of accuracy.

[11] Tirole, 1988 *The Theory of Industrial Organization* MIT notes that "*In others [markets],prices may remain somewhat hidden, for instance when manufacturers sell to a small number of big buyers.*"

4.2.2 Other constraints on behaviour

The foregoing notes that the characteristics do not necessarily predispose monopoly pricing. In this section we review other constraints on behaviour. In particular:

- the availability of additional transmission into the NSW and ACT market is such that capacity is unlikely to be fully utilised unless there is substantial growth in gas fired generation in that market;

- given current well-head prices and expected long-run prices in the electricity market, the maximum gas transmission charge a gas fired generator would be able to pay is approximately $0.8/GJ, which is close to current prices and the indicative reference tariff estimated for EGP; and

- the impact of generation customers on pipeline profitability — 500MW of generation translates into an present value of revenue of about $130m — is likely to foster competition to secure these customers.

Pipeline capacity

The data in Figure 4-1 showed that the existing pipelines have committed sufficient capacity to meet demand for at least a five year period without additional capital expenditure on new compressor facilities. However, both EGP and EAPL MSP are able to expand their capacity well beyond the current capacity constraints by adding further compression.

EGP would be able to increase its gross capacity from 55PJ/annum to 110PJ/annum at a long-run marginal cost of between $0.03/GJ and $0.17/GJ. EAPL would be able to expand its gross capacity from 172PJ/annum to 290PJ/annum a long-run marginal cost of between $0.02/GJ and $0.12/GJ.[12] These compare to proposed tariffs of $0.71/GJ for EAPL MSP and $0.86/GJ for EGP. Hence, it is clear that pipeline capacity constraints[13] are only likely to become binding at present levels of demand growth by 2030.

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12 Estimate of the long-run wholesale electricity prices in NSW are presented in Appendix 0.

13 A capacity constraint can be considered to be a substantial increase in the marginal costs of additional capacity. In the limit this is equal to the value of unmet demand.

This does not take account of the potential for augmentation of the interconnector, which could contribute 70 to 90 PJ with additional compression and looping.[14]

Gas for electricity generation

The Council considers that the market for electricity and gas sales in SE Australia are distinct:

> *The Council considers that the product dimension of the relevant other market is natural gas. While other energy sources, such as electricity, provide some competitive discipline on the sale of natural gas, the field of rivalry between these energy products is not so close as to integrate the markets.*

We concur with this view; electricity and gas are only substitutes in demand for a limited number of customers, and substitution decisions are generally made infrequently at times of market entry or significant capacity expansion. Nor is there scope for supply side substitution.

None the less, as the NCC notes in its draft, the electricity market exerts a profound influence on the gas market:

> *Secondly, because one of the uses of gas is as an input for electricity production, its price continues to be constrained by the price of electricity to some degree even after these investments are made.*

In our view, the use of gas for generation imposes a substantial constraint on gas pipeline prices over and above that recognised by NCC, because:

- prices for gas, and hence prices for transportation, are disciplined by prices for alternate fuels, particularly coal, for generation and by prices that prevail in the electricity market; and

- new gas fired generation represents an important source of potential revenue to pipeline service providers — new generators generally enter into long-term contracts for gas supply and associated transportation, which therefore lock in revenues for pipeline owners for long periods. Accordingly, there are strong incentives for pipeline owners to compete on price to secure these contracts.

We review each of these issues in turn.

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14 NSW Ministry of Energy and Utilities, 1999b claims the Interconnect could be upgraded to around 90 PJ per year, while EAPL and the Gas Transmission Corporation of Victoria claim the Interconnect could eventually carry around 70 PJ per year.

Gas as a source of fuel for electricity generation

Gas is probably the preferred fuel supply for electricity generation, for a number of reasons:

- at current relative fuel prices, new gas fired generation is price competitive with black coal fired generation; and

- gas generation has environmental advantages deriving from high thermal efficiency and low emissions. The environmental advantages give greater scope over location, and reduce the risks associated with market based arrangements for pollution management.

Figure 4-4 shows an estimate of the maximum price of gas that would ensure that gas fired generation is competitive with coal fired generation. The analysis is somewhat conservative in that it ascribes a 90% load factor to the gas fired plant. In practice, excess coal and brown coal fired base-load generation in SE Australia would result in a lower load factor for gas fired plant. Even so, the figures show that at current ex field gas prices, transmission prices would have to lie between $0.61/GJ and $0.81/GJ for gas fired generation to compete. These values are lower than DEI's proposed reference tariff, and similar to EAPL's suggested reference tariff.

The value of new generation to a pipeline owner

Electricity market prices are likely to establish wholesale gas prices in the NSW. If the pipelines set access prices which make gas generation uncompetitive, or otherwise refuse access, then this would substantially reduce growth in demand for gas and for gas transmission. The net present cost of foreclosing on a 500MW gas plant (to either pipeline) is about $133m.[15]

Current electricity prices

At present, electricity prices in NSW and Victoria would not sustain entry for either coal or gas plant. Figure 4-5 and Figure 4-6[16] shown national electricity market prices across 1999 and in April 1999. The time weighted average price was $22.7/MWh in 1999. The time weighted average price in the 11 months to May 2000 was

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15 The calculation assumes a $0.17/GJ cost of transmission, a reference tariff of $0.80/GJ, a 15 year contract period and 10% discount rate.

16 This figure illustrates the assumption made in Figure 4-4, namely that the expected load factor for gas fired generation would be below that of an equivalent sized coal plant. The marginal cost of gas plant, at $24/MWh, would result in economic dispatch for less than 8 hours of the day in April 1999.

$26.5/MWh, still significantly below the level that would support new entry by either gas fired or coal fired generation. This is a reflection of the excess supply of generation in these markets. Even so, pipeline owners have incentives to discount to gas fired generators.

There are significant first mover advantages in electricity markets which derive from the lumpy nature of investment. Since an individual entrant is large in comparison with the overall size of the market,[17] entry tends to depress post-entry prices for a period of time, forestalling further entry. Hence, pipelines have an incentive to facilitate early entry through their pricing strategies in order to secure transportation contracts. Furthermore, a typical entry strategy would involve incremental development of a generation site, so an initial contract can be expected to be followed by additional transport contracts.[18] This further fosters a willingness for pipeline owners to compete on price for generation customers.

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17 For example, Pelican Point in South Australia represents 16% of South Australia's electricity market. A 500MW CCGT in NSW would represent approximately 3% of peak demand in the combined NSW/Victoria market.

18 Again, Pelican Point is a good example of this.

Figure 4-4. Estimation of maximum price of gas for electricity generation

For this gas-fired electricity generation to enter the NSW market, it would need to be lower cost than the competing coal-fired technology. This fact, in conjunction with reasonable assumptions about the relative capital costs of the two competing technologies and the fuel cost of coal places an upper limit on the wholesale prices of gas. The table below present estimates of the 'net back' value of gas used in power generation, expressed in terms of the maximum fuel cost a CCGT could bear (in $/MWh).

Estimates of the maximum fuel cost for a CCGT in NSW*

Parameters	Coal	Gas
Capital cost, $/kW (assumed)	$1,500	$750
Asset lifetime, years (assumed)	25	25
Load Factor (assumed)	95%	90%
Capital cost, $/MWh	$18.9	$12.0
Fuel cost, $/MWh	$15.0	$23.4
Non-fuel O&M, $/MWh	$1.5	$0.0
Total cost, $/MWh	$35.4	$35.4

The table shows the maximum fuel cost a base-load CCGT would be able to bear ($23.4/MWh on a sent out basis) in order to displace coal as the preferred entry candidate. The capital cost estimates are at the lower end of expectations, and therefore assume a limited requirement for new fuel supply and transmission infrastructure. The load factor for gas is lower than for coal because we would not expect gas fired plant to operate during off-peak hours.

We do not have data on contract costs for coal in NSW. However, we note that in 1999 electricity pool prices at times when coal could be expected to be operating at the margin were typically between $13/MWh and $20/MWh. Hence, the assumption of $15.0/MWh for marginal fuel costs is relatively conservative.

Assuming an efficiency factor of the gas-fired plant of 51%** (being that of a CCGT plant), the gas fuel cost of $23.4 per MWh translates to a price of $3.31/GJ. Assuming a wellhead price of between $2.50/GJ and $2.70/GJ,*** this translates to a maximum allowable transmission price of between $0.61/GJ and $0.81/GJ. Both these values are below the reference tariff proposed by Duke in its draft Undertaking.

* Assuming no changes in relative fuel prices as a result of environmental changes.

** The model on which this analysis was based used an efficiency rate of 6700 mbtu/kWh, which translates to an efficiency of 51%.

*** These indicative prices were suggested by Duke.

Figure 4-5. Annual average daily NEM prices in NSW (1998/99)

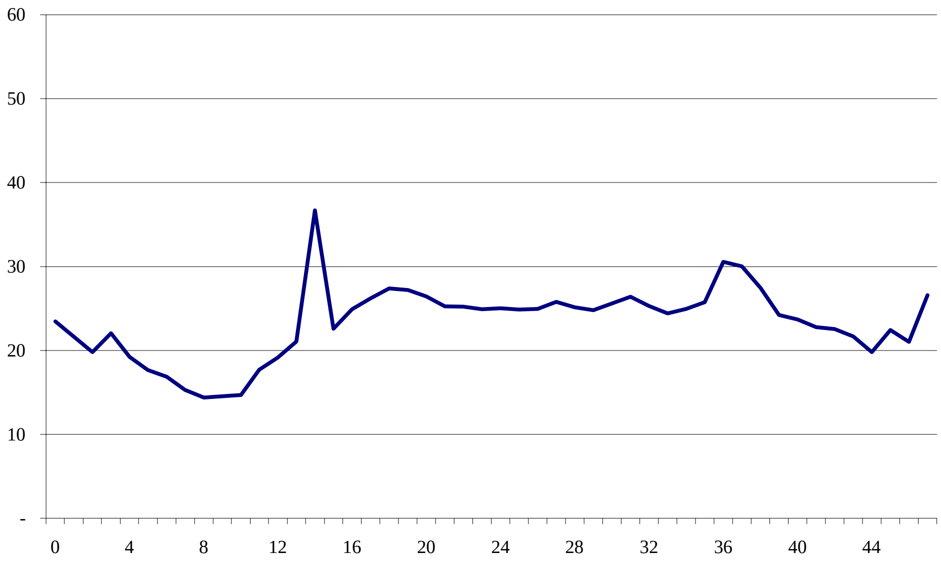
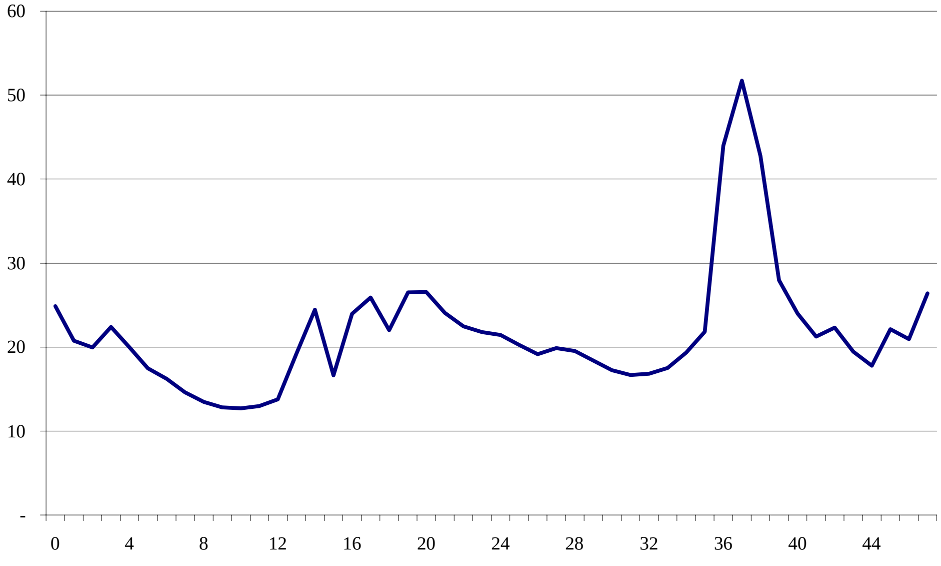


Figure 4-6. April 1999 average daily NEM prices in NSW



Figures show prices in the National Electricity Market in NSW. The charts present 'average' daily profiles comprising the average of prices at 00:30, 01:00 etc across the whole period represented.

Gas trading by electricity generation

It is possible that gas pipelines would attempt to minimise the impact of price competition to secure gas fired generation. However, in order to do so they would have to impose constraints on the on sale of gas to the wholesale/retail market in NSW. In our view, this is unlikely. Generators would be highly reluctant to enter into such contracts, since it would effectively render them unable to respond to arbitrage conditions in the gas and electricity markets.

Geographical dimension of the effect

The impact of electricity prices on gas prices does not solely apply to those regions of the gas market supplied by more than one pipeline. Rather, electricity prices can be expected to discipline prices throughout NSW and Victoria.

Conclusion

While access to EGP and EAPL MSP is likely to foster competition in upstream and downstream markets, it is not clear that the coverage *at this point* under the Gas Code would increase access to any significant extent:

- absent coverage, competition between the pipelines could well result in prices below the reference tariffs one would anticipate under the Gas Code;
- coverage may, itself, foster collusive outcomes, minimising the prospect of price competition below the level established in reference tariffs;
- there is a low likelihood of adverse outcomes if neither pipeline is covered; and
- no coverage or revocation of coverage at this time would not preclude:
  - Declaration of one or both pipelines at some time in the future;
  - one or both pipelines in the future submitting voluntary Undertakings that specify access arrangements; or
  - a recommendation by the NCC at some point in the future that the pipelines should be covered, in response to an application.

4.2.3 Market definition

The foregoing is based on the market definition put forward in the NCC's draft recommendation, which defines the relevant market as the wholesale market for gas in SE Australia:

> *The Council considers that the functional dimension of the relevant other market is sales between natural gas producers and users/consumers, including intermediaries and aggregators. There is some question whether there is a retail market separate from a wholesale market, but the Council does not consider that anything turns on this question.*
>
> *The Council considers that the geographic dimension of the relevant other market is south east Australia*

In our view, this is the appropriate market to examine when reviewing criterion (a), whether access promotes competition in another market. However, as previously indicated, electricity prices place a significant constraint on prices that prevail in this market, and hence on pipeline tariffs.[19]

4.2.4 Regions supplied by one pipeline

However, the Council is careful to distinguish areas in the market which are supplied by a single pipeline and those served by more than one pipeline, and then recommends that pipelines or portions of those pipelines supplying those regions are covered. First, the NCC notes that:

> *This geographic dimension relies on the assumption that producers and users have access to the network of pipelines described above, on reasonable terms and conditions. This access has been, or will be, provided because either:*
>
> - *the regulation of third party access to monopoly pipelines; or*
> - *the pipelines would provide appropriate access of their own accord.*

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[19] In this respect, it is instructive to examine energy markets in the US where gas is the preferred form of new generation — for example, California and the north eastern states. In these markets wholesale gas and electricity prices are very closely linked. Indeed, financial instruments are traded which are specifically designed to take advantage of (and in so doing, close) any arbitrage opportunities that do arise. These contracts are often referred to as 'spark spread' contracts.

And then states:

> *Regions that are supplied gas through a single transmission pipeline would not be included within the south east Australian gas sales market if restrictions on access to those pipelines reduce the potential for supply side substitution. Coverage of these pipelines ensures that regions are integrated into the field of rivalry for gas producers in south east Australia.*

We have some concerns about this approach. The same pipeline is used to serve those areas identified by the NCC — in the case of EGP the region south of the off-take for the ACT — as those areas which are supplied by multiple pipelines. Accordingly, we would expect pricing and access in the competitive region of the market to affect prices and access elsewhere for the following reasons:

- the threat of regulation is, in our view, greater when the pipeline operates in regions where it is a sole supplier *and* in regions where there are competing pipelines. This is particularly so when the competitive regions are at the end of the pipeline, and so make use of all pipeline assets; and

- we would expect retailers operating in the ACT and NSW markets to also seek to retail gas at other points south of the ACT. This will impact on pipeline pricing behaviour; and

- the use of gas for electricity generation would continue to discipline prices, for the reasons discussed above.

The threat of regulation

The ACT and Sydney regions of the market are supplied by both EAPL MSP and EGP. The Council is not currently recommending the coverage of EGP in respect of this section of the pipeline. However, it is recommending coverage of EGP south of this. It is difficult to see why EGP would have incentives to set prices to the south of ACT which restrict access. Pipeline operators, in the face of potential regulation, would find it very difficult to set prices in those regions where it is a monopoly supplier which are greater than prices elsewhere. This would be particularly problematic when the monopoly regions use only a strict subset of the assets needed to supply the remaining regions. One would expect a regulator to be made aware of such behaviour.

Furthermore if, as the NCC suggests, there is some form of monitoring of pipeline behaviour, this type of pricing behaviour would become particularly difficult to implement.

Retailers operating south of the ACT

We would expect most of EGP actual and prospective retailing customers to be interested in retailing in regions south of the ACT. They would therefore seek access to EGP for this purpose. They would be in a strong position to prompt regulatory action if access in these smaller markets was refused or restricted. Figure 4-7 lists licensed gas retailers in NSW who are likely to be interested in retailing in regions south of the ACT.

Figure 4-7. Licensed gas suppliers in NSW with other SE Australian retail activity

AGL Energy Sales and Marketing Limitec
AGL Retail Energy Limited
Allgas Energy Ltd
CitiPower Pty
Eastern Energy Limited
EnergyAustralia
Energy 21 (now Origin)
Great Southern Energy
Integral Energy
Powercor
United Energy Limited

4.3 Economic to duplicate

An assessment of whether it is economic to duplicate EGP has to be made by reference to the service provided by means of "*a covered pipeline*."[20] This predisposes a point to point service definition, in this case from Longford to Sydney which is, indeed, the interpretation presented by the NCC.

> *The Council concludes that the relevant services are the transportation of natural gas between Longford and Sydney, backhaul, interconnect, and linepack.*

The problem with this approach is that it almost compels that the economic to duplicate test is interpreted in terms of whether it would be economic to duplicate the pipeline in question. When this test is applied — as applied by the Council — we would concur with their conclusion, that it would not be economic to build a new pipeline to provide the services of the EGP. EGP, from the outset of its operation, will have substantial spare capacity which can be brought into use at low cost; hence, it is unlikely to be efficient to duplicate the EGP pipeline facility.

[20] The terminology used in the Gas Code.

However, it is entirely reasonable to expect that other pipelines could serve the SE Australian gas sales market and increase competition in that market (as the addition of EGP to the EAPL MSP has done). They might not provide the same transportation function as an existing pipeline, but such hypothetical pipelines could, nevertheless, exert an effect on the pricing of EGP and may be commercially viable. Under its narrow definition of 'economic to duplicate,' we would expect the Council to deem that these new pipelines are uneconomic to duplicate. This appears to be somewhat unsatisfactory; it can lead to a decision for coverage even in circumstances where alternative pipelines (actual or potential) serving the same market but with different origins or destination exist or could be constructed which would discipline monopoly pricing by incumbent pipelines.

The problem is likely to arise when the pipeline has a geographical dimension that is narrower than the geographic dimension of the market in which competition is promoted.

The Council also concludes that:

> *the duplication of AGL's Wilton to Horsley Park pipeline in fact constituted uneconomic development of the Eastern Gas Pipeline such that this part of the Eastern Gas Pipeline satisfies criterion (b).*

This conclusion is troubling, for a number of reasons:

- for the reasons discussed above, the narrow adoption of pipeline service definitions that are inconsistent with the geographic dimension of the promoted market necessitates a finding of 'uneconomic' to duplicate; and

- it ascribes no efficiency benefit to Duke's legitimate commercial interests. In particular, Duke considers that the flexibility it derives from ownership of the pipeline through to Horsely Park is important to its competitive position in the supply of transport services to the Sydney market.

4.4 Public interest

There are a number of possible components to the public interest test. In addressing this criterion, we would submit that the Council should consider:

- the term over which to assess the coverage decision;
- the degree to which coverage provides the most efficient means of developing competitive outcomes in upstream and downstream markets; and
- the impact of partial coverage in some regions on outcomes elsewhere.

4.4.1 Term of the coverage decision

There are a number of factors which suggest that it would be in the public interest to delay a coverage decision on EGP and to revoke the coverage of EAPL MSP. The current situation is somewhat unique in that coverage is sought over a yet to be commissioned gas pipeline, which has already contracted to provide access to a number of downstream and upstream market participants.

Hence, the NCC is being asked to make a coverage decision in the absence of any experience of actual market outcomes with both pipelines in operation without coverage, and is being asked to address either:

- whether coverage would increase access to either pipeline; or
- if access *per se* is the appropriate interpretation of criterion (a), whether coverage under the Gas Code, considering the range of alternative mechanisms, is likely to produce the most efficient outcomes.

This is a challenging task. Given the uncertainty over precise outcomes, including the possibility that coverage under the Gas Code could result in worse outcomes than no coverage (which would presumably mean coverage is against the public interest), it is relevant to consider whether refusing or removing coverage would result in harm.

We consider that there is a low likelihood of adverse outcomes in the medium term, given that:

- a substantial quantum of required transmission is already under contract, so prices are already set;
- there is significant excess transmission capacity available at very low marginal cost;
- the prospects of significant promotion of competition in another market over the same period are limited; and
- there are external constraints on behaviour, such as the requirement to set competitive transmission prices for gas fired generation.

Finally, if there is evidence in the future that some form of regulated access is required, opportunities for regulation via an Undertaking, a Declaration or a subsequent application for coverage are not foreclosed by a decision not to cover EGP and to revoke cover on EAPL MSP at this time. Of course, there would be costs associated with a subsequent decision to regulate, but in mitigation of these costs we note that:

- the EAPL MSP access regime has not yet been agreed, and the work that has been undertaken to date in its preparation would not be lost;
- EGP has not yet prepared access arrangements; and
- there is a high likelihood that EGP and EAPL MSP would submit voluntary arrangements in the period which would reduce the requirement for substantial re-regulation cost.

4.4.2 Development of competition

We have argued that the appropriate interpretation of criterion (a) of the Gas Code is whether access or increased access *that results from coverage* would facilitate competition in another market. Hence, this suggests a two part test:

- whether coverage increases access; and
- whether the access then facilitates competition.

The arguments for assuming that coverage at this time will result in access in excess of access that would be granted with no coverage are weak.

However, we recognise that the Code could be interpreted differently. It does not specify that access *as a result of coverage* should facilitate competition, only that access under the Code should do so. Under this interpretation, we submit that the public interest test must address whether coverage then provides the best means of securing access. Given the range of alternatives and the uncertainty over the effects of coverage on, it is difficult to show that this is so.

4.4.3 Impact of differential coverage

The NCC has not finalised its recommendations on coverage, but explores the possibility of partial coverage. In the foregoing, we argue that there are grounds for arguing that EGP does not satisfy the criteria for coverage, particularly in the short-term, even in those regions where it is the only pipeline operator. In our view, there are public interest arguments against coverage of the southern component of the pipeline, even if there is some risk of monopolistic access pricing, as follows:

- the information disclosure related to assets south of ACT would provide a substantial quantity of information about the overall pipeline. These would reduce price secrecy elsewhere in the market and increase the prospect of tacit collusion;

- there would be significant additional costs associated with operating regulated and unregulated pipeline activities;

- demand for gas south of the ACT is likely to remain only a small portion of the SE Australian gas market. DEI estimates that it represents perhaps 3% of the overall market, although this might increase with the commissioning of gas fired generation in this region; and

- in the specific event of access for gas fired generation, prices in the electricity market can be expected to discipline gas pipeline pricing.

Accordingly, given the small size of the market south of ACT, it is doubtful whether the cost of coverage (in compliance costs and in the impact on outcomes in NSW and ACT) would outweigh the benefits of coverage.

Appendix 1 — Estimates of marginal costs

The following presents the calculations of long-run marginal costs (LRMC) for gas transportation on EGP and EAPL MSP, assuming that each pipeline solely provides a base-load transport service from the relevant field to the NSW and ACT market.

A1.1 Data and model

This appendix presents calculations of the marginal costs for EGP and EAPL MSP. The approach used to estimate the marginal costs is as follows:

- cost models for EGP and EAPL were constructed based on Duke's financial model of EGP. The model was adapted to represent EAPL;
- data for EAPL for inclusion in the model was derived from public domain data made available by EAPL;
- all past capital costs included in the calculations are excluded — in the case of EGP, construction costs are excluded;
- capital costs (primarily related to compressor facilities) are presented in the form of annuities assuming a 10% discount rate (taken from the DEI financial model) and a 15 year asset life.

A1.2 Approach

The LRMC estimates are based on two scenarios (see **Error! Reference source not found.** and **Error! Reference source not found.**) for each pipeline — low own demand forecasts and high own demand forecasts. For each of the four cases, the model was run assuming:

- that forecast demand was delayed by one year, triggering a consequent delay in new capital expenditure; and
- that forecast demand was moved forward one year, triggering a consequent advance in new capital expenditure.

The LRMC estimates were calculated as the net present value of the change in costs divided by the net present value of the change in volume.

[Tables at the end of this Appendix removed as commercial-in-confidence]