Australian
Competition &
Consumer
Commission

EAPL's application to the NCC for partial revocation of coverage of the Moomba to Sydney Pipeline System

September 2002

CONTENTS

Executive summary ii

1. Introduction 1

2. Background 2

2.1 Commission's draft decision on MSP access arrangement 2
2.2 NCC's draft recommendation on revocation application 2

3. NECG's criticism of the Commission's Draft Decision 4

3.1 Economic life of the MSP 4
3.2 Deferred tax liabilities 5
3.3 Optimised replacement cost and contingency factors 5
3.4 Risk 6
3.5 Effective versus statutory tax rates 9
3.6 Working capital 10

4. Hypothetical New Entrant Test 11

5. Conclusion 12

Executive summary

In June 2001 the National Competition Council (NCC) received an application from East Australian Pipeline Limited (EAPL) for revocation of coverage under the National Third Party Access Code for Natural Gas Pipeline Systems (the Code) of certain sections of the Moomba to Sydney Pipeline System (MSP).

In December 2001 the NCC made its draft recommendation to the Minister that EAPL's application for partial revocation of coverage of the MSP should not be approved and that the MSP should remain a covered pipeline under the Code.

In reaching this conclusion the NCC relied on material contained in the Commission's Draft Decision, which was released in December 2000, on EAPL's proposed access arrangement. In particular the NCC noted that tariffs proposed by the Commission in its Draft Decision were up to 40 per cent less than EAPL's tariffs. NCC stated that this is evidence that EAPL has substantial market power to distort competition in dependent upstream and downstream markets.

In response to the NCC's draft recommendation, the Network Economics Consulting Group (NECG), on behalf of EAPL, made a submission to the NCC in which it was critical of the NCC's use of the Commission's tariff calculations and the NCC's conclusion that the difference between the MSP's actual tariffs and the ACCC's proposed tariffs is evidence that EAPL has market power. NECG argued that, firstly, the ACCC did not correctly apply the provisions of the Gas Code in its tariff calculations, and secondly, even if it did, tariffs calculated using the principles of the Code are somewhat irrelevant as an indicator of contestable market prices, as the Code does not apply the 'hypothetical new entrant test' (HNET). The Commission considers both these matters in this submission.

NECG criticised the Commission's application of the Code in deriving reference tariffs on several grounds, including: inconsistent use of asset lives when calculating the value of the initial capital base and forward depreciation; understatement of the optimised replacement costs; underestimation of risk; use of an effective rather than a statutory tax rate; exclusion of a return on working capital; and deducting accumulated deferred taxes from the value of the asset base.

With respect to the HNET, the Commission engaged the services of the National Economic Research Associates (NERA) to critique the NECG report, in which NECG concluded that EAPL's current tariffs are consistent with the HNET. While NERA agreed that the HNET may be an appropriate benchmark to gauge monopoly pricing, it was critical of the manner in which the NECG applied the test to the MSP. NERA concluded that the HNET tariff is $0.51/GJ, which is significantly below EAPL's current tariffs and is evidence that EAPL is exercising market power.

A major difference in the approaches adopted by NECG and NERA is that NECG bases tariffs on MSP volumes whereas NERA uses market volumes (MSP volumes plus volumes transported by Duke Energy's Eastern Gas Pipeline). According to NERA it would be more efficient for one pipeline to serve the NSW/ACT market than two pipelines.

1. Introduction

This submission by the Australian Competition and Consumer Commission (the Commission) is in response to a submission from the Network Economics Consulting Group (NECG) dated 11 February 2002 to the National Competition Council (NCC). NECG's submission, on behalf of EAPL, was made in response to the NCC's draft recommendation on East Australian Pipeline Ltd's (EAPL's) application for revocation of coverage of parts of the Moomba to Sydney Pipeline System (MSP).

In its submission NECG was critical of the manner in which the Commission applied the National Third Party Access Code for Natural Gas Pipeline Systems (the Code) to determine proposed reference tariffs in the Draft Decision on EAPL's proposed access arrangement as originally submitted. NECG was also critical of the NCC's use of the Commission's proposed reference tariffs to conclude that EAPL is exercising market power and earning monopoly rents. According to NECG, the 'hypothetical new entrant test' (HNET) is the appropriate benchmark for determining competitive prices when considering coverage under the Code, rather than relying on tariffs determined in accordance with the Code.

This submission considers some of the criticisms raised by NECG of the Commission's Draft Decision. It also outlines the findings of the National Economics Research Associates (NERA) in relation to the issue of the HNET. The Commission engaged the services of NERA to critique NECG's report.

The Commission emphasises that this submission relates to the matter before the NCC (the application for revocation) and is not directly related to the Commission's consideration of EAPL's proposed access arrangement. In particular, the Commission's comments in this submission responding to NECG's criticisms of the Draft Decision are not to be construed as pre-empting the Commission's Final Decision.

At the time of making this submission, the Commission had released its Draft Decision, but had not yet made its Final Decision with respect to the access arrangement. The Commission is currently considering all material before it, including submissions in response to the Draft Decision, a revised access arrangement submitted by EAPL in June this year and submissions received on the revised access arrangement. In making its Final Decision, the Commission will also consider NECG's submission to the NCC and NERA's report on the HNET. The Commission anticipates that its Final Decision will be released later this year.

Although, the Code does not apply the HNET in the context of the determination of access arrangement reference tariffs, nevertheless the HNET has some relevance to the Commission's assessment of EAPL's proposed access arrangement. The HNET is one mechanism for deriving a competitive (hypothetical) market price for an industry that may not be subject to competition. The outcomes of a competitive market is one of the principles that the Commission must take into account in determining reference tariffs. Accordingly, the Commission considered that it was appropriate to consider and respond to NECG's assertions on the HNET.

Having said that, however, the tariff determined in accordance with the HNET is not necessarily the appropriate value of the reference tariff that the Commission would derive from the application of the code. Replication of a competitive market is only one of many factors that the Commission must consider in determining reference tariffs.

The remainder of this submission is structured as follows:

- Section 2 provides some background material to EAPL's proposed access arrangement and application to the NCC for revocation;
- Section 3 discusses some of the issues raised by NECG with respect to the Draft Decision; and
- Section 4 address the issue of the HNET.

2. Background

2.1 Commission's draft decision on MSP access arrangement

In December 2000, the Commission released its Draft Decision on EAPL's proposed access arrangement for the MSP. The proposed access arrangement was submitted in accordance with the Code. An access arrangement describes the terms and conditions, including tariffs, on which the pipeline owner (or operator) will make access to the pipeline available to third parties.

In June 2001, the Commission agreed to a request from the Australian Pipeline Trust (APT), on behalf of EAPL, to defer releasing its Final Decision pending resolution of EAPL's application to the NCC for partial revocation of coverage of the MSP under the Code. At that time the Commission indicated, however, that it would review its position in six months. Following release of the NCC's draft recommendation, the Commission reviewed its position and decided not to agree to APT's request for a further postponement. The Commission decided instead to progress its consideration of the access arrangement to final decision stage.

EAPL submitted a revised access arrangement on 30 April 2002 and supporting access arrangement information on 20 June 2002. These documents were released publicly and the Commission called for submissions from interested parties by 12 July 2002. Four submissions were received. The Commission is currently assessing EAPL's revised access arrangement and anticipates that it will release its Final Decision before the end of this year.

2.2 NCC's draft recommendation on revocation application

In June 2001 the NCC received an application from EAPL for revocation of coverage under the Code of certain sections of the MSP (Moomba to Wilton mainline and Dalton to Canberra lateral). Other laterals of the MSP (Young to Culcairn, Young to Lithgow and Junee to Griffith) would remain covered under the Code. If successful, EAPL's application for revocation would relieve it of the obligation to submit an access arrangement under the Code to the Commission with respect to the Moomba to Wilton mainline and Dalton to Canberra lateral.

In December 2001, the NCC made its draft recommendation to the Minister that EAPL's application for partial revocation of coverage of the MSP should not be approved and that the MSP should remain a covered pipeline under the Code. The NCC concluded that the criteria for revoking coverage (pursuant to section 1.31 of the Code) were not met.

In particular, the NCC concluded that coverage of the MSP would reduce impediments to entry in the upstream market for the production of natural gas in the Cooper Basin and the downstream markets for the delivery and sale of natural gas. The NCC stated that EAPL is currently pricing substantially above long-run economic costs of providing transportation services.[1] The NCC further stated that this is evidence that EAPL has substantial market power to distort competition in dependent upstream and downstream markets.

In reaching this conclusion the NCC relied on material contained in the Commission's Draft Decision. In particular the NCC's consultants (Ordover and Lehr) noted that tariffs proposed by the Commission in its Draft Decision were up to 40 per cent less than EAPL's tariffs. Neither the NCC nor Ordover and Lehr evaluated the Commission's analysis. Ordover and Lehr did note, however, that even allowing for a margin of error of ten per cent, EAPL's tariffs would still be significantly higher than those proposed by the Commission.

In response to the NCC's draft recommendation, NECG was critical of the NCC's use of the Commission's tariff calculations in its Draft Decision and NCC's conclusion that the difference between the MSP's actual tariffs and the ACCC's proposed tariffs is evidence that EAPL has market power.

There are two main themes to NECG's paper:

- firstly, the ACCC did not correctly apply the provisions of the Gas Code in its tariff calculation: and

- secondly, even if it did, tariffs calculated using the principles of the Code are somewhat irrelevant as an indicator of contestable market prices, as the Code does not apply the 'hypothetical new entrant test' (HNET).

---

[1] Although the MSP is a covered pipeline under the Code, its current tariffs are unregulated and will remain so until the Commission has completed its assessment of the access arrangement.

3. NECG's criticism of the Commission's Draft Decision

NECG highlights the following areas where it considers that the Commission applied the Code incorrectly or inconsistently in its Draft Decision:

- the use of a different asset life (50 years) to calculate to the depreciated optimised replacement cost (DORC) to that used to calculate forward depreciation (80 years);
- the use of an asset life of 80 years for the Moomba to Sydney mainline is inconsistent with its remaining economic life;
- deducting the amount of accumulated deferred taxes from the asset base;
- removal of the contingency factor of $84 million from the value of the optimised replacement costs (ORC);
- the weighted average cost of capital is too low as, firstly, the Commission underestimated risk and, secondly, the Commission used an effective rather than the statutory tax rate; and
- the Commission incorrectly excluded the cost of working capital from its calculation of the required revenue.

The issues raised by NECG will be considered as part of the Commission's assessment of EAPL's access arrangement in reaching the Final Decision. Some issues, however, are considered below.

3.1 Economic life of the MSP

NECG argues that the Commission erred in its use of an asset life of 80 years (remaining life of 56 years) for the Moomba to Sydney mainline. NECG argues that the economic life of the Moomba to Sydney mainline is 60 years (remaining life of 36 years).

An asset life of 60 years for the Moomba to Wilton section of the MSP (in contrast with 80 years for the laterals) is the asset life originally proposed by EAPL. The difference in asset lives reflects the older technology and some deterioration of the Moomba to Wilton mainline. The Australian Pipeline Trust (APT), however, submitted to the Commission in September 2000 that the life of the Moomba to Wilton section could be extended to 80 years through refurbishment costs (estimated to commence in the year 2033).

EAPL also submitted that Moomba will become a hub for gas to be supplied to Sydney from PNG and/or the Timor Sea when gas supplies in Moomba are depleted, indicating that there will be demand for transportation services for the whole technical life of the MSP. Based on the evidence put to it by APT, the Commission proposed that the asset life of the Moomba to Sydney mainline was 80 years. Accordingly, as the Moomba to

Sydney mainline was 24 years old, a remaining life of 56 years was used in the Commission's Draft Decision to calculate forward-looking depreciation.

NECG's position conflicts with the position that EAPL itself adopts in relation to its revised access arrangement. EAPL reiterates that in its opinion the appropriate life of the Moomba to Sydney mainline is 80 years (without the qualification that refurbishment is needed to extend the life). EAPL states:

> The life of 80 years is adopted for the pipelines consistent with industry and regulatory practice. Based on current information, EAPL does not believe it is appropriate to assume that the Moomba to Wilton Pipeline has an economic life less than 80 years.[2]

3.2 Deferred tax liabilities

NECG argues that the Commission is inconsistent in its decisions with respect to the treatment of deferred tax liabilities. NECG notes that the value of deferred tax liabilities is deducted from the value of the asset base in the MSP Draft Decision, but is not deducted from the asset base in the Moomba to Adelaide Pipeline System (MAPS) Final Decision.

The Commission reviewed its position between the MAPS draft and final decisions and decided not to deduct the amount of deferred tax liabilities from the asset base in that case. The MAPS Final Decision was released in September 2001.

In the case of the MSP Draft Decision, adding back the value of deferred tax liabilities of $37 million to the asset base would add only about $0.03 to reference tariffs.

3.3 Optimised replacement cost and contingency factors

NECG considers that it is appropriate to factor into the ORC a contingency factor in case of construction cost overruns. NECG stated that a new entrant would include a construction contingency in its own estimate of the efficient cost it can offer its customers.[3]

This issue was addressed by NERA in its report on the HNET. NERA stated:

> We understand that the use of contingency amounts in planning the construction of assets such as a pipelines is common practice. In this situation the contingency does not reflect the expected cost of the pipeline but rather reflects an estimate of the highest cost that is likely to be incurred above the expected cost of the pipeline. By definition it is equally likely that costs will come in under the expected costs as that they will go over the expected costs. However, it is sensible to plan for a contingency in which costs exceed expected costs in order to avoid the (potentially) costly requirement to negotiate further finance in the event of such cost overruns.

---

2 EAPL, *Revised access arrangement – information requested in ACCC letter dated 27/5/02.*

3 NECG, *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price*, 11 February, 2002, p. 13.

> However, if all firms in the economy priced as though their asset costs were 10% more expensive than in fact they were on average there would be excess profits being earned. This would in turn attract new entrants until prices were reduced to only recover the expected costs of a new entrant. It is for this reason that the appropriate ORC value to use in the context of applying the hypothetical new entrant test does not include such contingency costs.[4]

3.4 Risk

NECG states that the asset beta for the MSP is an issue of contention. NECG states:

> The ACCC has chosen an asset beta value of 0.5 for the MSP—a figure which is equivalent to the Moomba-Adelaide Pipeline asset beta, and below the Victorian gas transmission asset beta of 0.55, despite the fact that both of these comparators face substantially less systematic risk. The MSP must contend with the simultaneous incidence of price regulation and competition with the unregulated Eastern Gas Pipeline. Since the commissioning of the EGP, the MSP has had significant amounts of uncontracted capacity.[5]

Systematic and non-systematic risk

Risk can be divided into two categories: systematic (non-diversifiable), and non-systematic (diversifiable) risk. Systematic risks are the market-related risks faced by an investor irrespective of the industry. Examples are the risk of political upheavals and economic up-turn or down-turn.

Compensation for systematic risk is made though the market-risk premium and beta factors found in the Capital Asset Pricing Model (CAPM). The CAPM provides compensation for systematic risk only, as firm specific risk can be eliminated through diversification. The equity beta is a statistical measure that indicates the riskiness of one asset or project relative to the whole market (usually taken to be the Australian stock market). With the market average being equal to one, an equity beta of less than one indicates that the stock has a low systematic risk relative to the market as a whole. Conversely, an equity beta of more than one indicates that the stock has a relatively high systematic risk.

Non-systematic risks are specific or unique to an asset or project and may include asset stranding, bad weather and operations risk. Such risks by their nature are specific and need to be assessed separately for each access arrangement. Importantly, non-systematic risk (specific risks) are independent of the market. For an investor, exposure to non-systematic risk related to an asset can be reduced or countered by holding a diversified portfolio of investments. Consequently, specific risk is not reflected in the equity beta parameter of the CAPM.

While other asset pricing models involving additional risk factors have been developed in the literature, the CAPM is currently still considered to be the dominant approach

---

[4] NERA, *The Hypothetical New Entrant Test in the context of Assessing the Moomba to Sydney Pipeline Prices*, August 2002, pp. 29-30.

[5] NECG, *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price*, 11 February, 2002, p. 13.

adopted in practice for estimating required rates of return.[6] The Commission considers that the CAPM is an appropriate framework for assessing the WACC facing natural gas transmission pipelines. The integrity of the CAPM model should be maintained in order to preserve the validity of its output. That is, it must only recognise risks of a systematic or market related nature. The Commission considers that the Code requires robust application of the relevant financial model under section 8.31 of the Code (in this case the CAPM). Accordingly, variations to the CAPM to take account of risks that are not purely of a systematic type are inappropriate. Non-systematic risks (specific risks) associated with a pipeline should not lead to an adjustment of beta – which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant bias.[7]

This approach is consistent with that adopted by the Federal Energy Regulatory Commission (FERC) in the USA whereby no additional allowance is made in setting the allowed rate of return for the 'risk' a pipeline service provider faces in needing to fill capacity.[8]

A matter of significant debate in the Commission's assessment of the Victorian access arrangement in 1998 was the treatment of specific (diversifiable) risk. As discussed above, the equity beta is meant to reflect only market related or non-diversifiable risks. Consistency with the CAPM framework therefore requires that specific risks be factored into projected cash flows rather than the cost of capital. The Commission indicated in its *Draft Statement of Regulatory Principles* that this is the approach that the Commission will normally adopt with respect to identified and quantified specific risks[9] and has done so in subsequent decisions. This is consistent with the former Office of the Regulator General's (now the Victorian Essential Services Commission (ESC)) assessment, as stated in its first consultation paper for the 2003 review of gas access arrangements:[10]

> … while events that are unique to particular businesses do not affect the cost of capital, they are not irrelevant. Rather, the price controls should be designed to ensure that the regulated entity expects to earn its costs of capital on average, taking account of all possible events.'

The Commission considers that loss of volumes to a new entrant is not evidence of systematic risk. Rather, it is a unique or specific risk, and as such, should be accommodated in the cash flows rather than in the CAPM formula. Under the Gas

---

6 K Davis & J Handley, *Report on cost of capital for greenfields investment in pipelines*, March 2002, p. 21.

7 K Davis & J Handley, *Report on cost of capital for greenfields investment in pipelines*, March 2002, p. 21.

8 NERA, *Regulation of Tariffs for Gas Transportation in a case of 'Competing' Pipelines: Evaluation of Five Scenarios*, October 2000.

9 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p.79.

10 Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No 1*, May 2001, p.60.

Code, compensation for reduced volumes or throughput on the MSP could be achieved by using the lower volume forecasts as the denominator in calculating the tariff from the revenue requirement. This is precisely the course of action that the Commission proposed in the MSP Draft Decision, despite advice from National Economic Research Associates (NERA) that, given the circumstances surrounding the MSP, current capacity rather than forecast volumes would be a more appropriate denominator for determining reference tariffs. NERA noted that this is the practice that is adopted in the USA.[11]

Empirical evidence on equity betas

The Commission's *Draft Decision* relied on a combination of empirical evidence, analysis of systematic risk facing the MSP and regulatory precedent to arrive at a value for the asset beta of 0.50 and equity beta of 1.16. The Commission recently engaged the services of The Allen Consulting Group to review the available empirical evidence on equity betas that might assist the Commission in assessing the appropriate beta to apply to gas transmission pipelines. The Allen Consulting Group found that if the Commission were to rely exclusively on the latest Australian evidence it would apply an equity beta of around 0.7. This is considerably less than the 1.16 proposed by the Commission in its Draft Decision on the MSP. In other words, had the Commission adopted an equity beta of 0.7, the return on equity (and hence return on assets) would have been less than that proposed by the Commission in its Draft Decision. The Allen Consulting Group stated:

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North American or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[12]

Although, the Allen Consulting Group concluded that current evidence indicates that regulators have erred in favour of regulated companies, it recommends that regulators adopt a conservative approach, at least in the short term. It stated:

> … while it inevitably is a matter for the Commission to decide how it exercises its discretion, it is recommended that, in the near term, it adopt a conservative approach, and not assume a proxy equity beta that is too far from the range of previous, relevant regulatory decisions. As noted above, these decisions typically have assumed a proxy beta (for the regulatory standard gearing assumption) of around 1. That said, this report has demonstrated that no implication can be drawn from current market evidence that the proxy betas that Australian regulators have adopted are likely to understate the 'true' beta – rather, as noted above, the current evidence suggests regulators systematically have erred in the favour of the regulated entities.[13]

---

[11] NERA, *Regulation of Tariffs for Gas Transportation in a case of 'Competing' Pipelines: Evaluation of Five Scenarios*, October 2000.

[12] The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.42.

[13] The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.43.

The analysis presented in the Allen Report is consistent with the findings of the ESC in its recent *Draft Decision* for the Victorian gas distributors. The ESC approved an equity beta of one, but indicated that this was on the generous side relative to current observations, which reveal an equity beta of less than 0.70 for Australian companies, and even lower for UK and US companies.[14] In approving an equity beta of one, the ESC made the following statement:

> The Commission has adopted a proxy equity beta of 1 for the Victorian gas distributors' regulated activities, for an assumed gearing level of 60 per cent. This is approximately equivalent to an asset beta of 0.40 for a debt beta of zero, or 0.51 for a debt beta of 0.18. However, the Commission emphasises that this estimate is well above that which would be derived exclusively with reference to the latest market data. That is, in deriving this proxy beta, the Commission has placed *considerable weight* on the desirability of continuity between regulatory decisions, and the long-term consequences of the Commission's decisions for the Victorian gas industry.
>
> However, the Commission notes that additional evidence from the capital markets will be available at future reviews of both the Victorian gas and electricity distributors. Barring mergers or other such activities, equity beta estimates for six comparable entities – AGL, Envestra, United Energy, Australian Pipeline Trust, AlintaGas and GasNet – using a full four years of observations will be available for all of these companies by the time of the 2008 gas access arrangement review. At that time, the Commission would envisage placing far more weight on the latest empirical estimates than it has at the current review.[15]

3.5 Effective versus statutory tax rates

The Commission's reasoning for not adopting the statutory tax rate in its rate of return calculations, and the flaws in using conversion formula to convert from a post tax return on equity (in accordance with the CAPM) to a pre-tax weighted average cost of capital (WACC), are well documented in the Commission's decision documents.

The Commission in its decisions therefore has adopted an approach where taxes are calculated on an 'as you go' basis. This involves using a post-tax WACC directly available from CAPM estimates to reflect the return on assets and capturing the impact of taxes in the cash flows. Such taxes are simply added, along with other capital costs and operations and maintenance costs, to calculate the target revenue requirement for the business. This approach avoids the need for a special conversion formula and handles tax in a very transparent way. To avoid price shocks to future users when taxes become payable, revenues are typically 'normalised' (smoothed) over time.

As the post-tax approach provides full compensation for actual tax liabilities as they occur, it avoids the need to calculate a long-term effective tax rate and problems generated by post-tax returns diverging from market rates over time. As far as the business is concerned, the post-tax approach would remove any risks associated with

---

14 The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.243.

15 The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.244.

future tax liabilities and provides a return always commensurate with market requirements.

To use a conversion formula that includes the statutory rate to convert from a post-tax return on equity to a pre-tax WACC when the effective tax rate is less than the statutory tax rate (because of, for example, accelerated depreciation for tax purposes) would result in a higher expected return on equity than that determined by CAPM estimates. In other words, the regulatory return on equity would be higher than the return expected by investors.

3.6 Working capital

NECG noted that the ACCC had ruled out the line item of non-capital costs relating to a return on working capital, resulting in an immaterial difference of $85,000 in 2001. The Commission stands by this position, as discussed below.

While it could be argued that a return on working capital meets the description of non-capital costs in section 8.36 of the Code, the Commission has not allowed explicit compensation for such costs in the *Draft Decision* for the MSP. This is because the model used to calculate the revenue requirement implicitly compensates for a return on working capital. To provide explicit compensation for a return on working capital in conjunction with the Commission's modelling approach would double count the return on working capital element.

The modelling adopted by the Commission assumes that all cash flows occur at the **end of the year** when in reality cash flows occur during the course of the year. Hence a feature of the Commission's approach is that the return on assets is calculated on the opening asset base (plus capital expenditure incurred during the year) rather than on average assets. Were the Commission to include an allowance for working capital, it would have to adopt more sophisticated modelling techniques which more accurately reflect the timing of cash flows over the course of the year. Any allowance for a return on working capital would likely to be significantly offset by a reduction in revenue as a result of greater precision in the modelling of cash flows.

This conclusion is supported by a report recently produced by The Allen Consulting Group, in which it concluded:

> The question posed at the start of this report was whether it would be appropriate for the Commission to include an additional allowance in respect of working capital when assessing reference tariffs. The results above imply that such an allowance is unnecessary – while there may be a (small) financing cost associated with operating expenditure, any shortfall from not including an allowance in respect of working capital is likely to be swamped by the favourable allowance provided in respect of capital assets under the PTRM [post tax revenue model] target revenue formula. It follows that if the Commission were to pursue further precision in relation to the assumptions it makes about the within-year timing of cash flow – which underpins the arguments for a return on working capital – then the likely outcome is that the more precise target revenue would be *lower* than that derived using the PTRM.[16]

---

[16] The Allen Consulting Group, *Working Capital Relevance for the Assessment of Reference Tariffs*, March 2002, p. 24.

While empirical evidence used by The Allen Consulting Group relates to the Moomba to Adelaide Pipeline, the same principles apply to the MSP.

It is worth noting that in its revised access arrangement EAPL has not included an allowance for working capital.

4. Hypothetical New Entrant Test

In its submission NECG argued that in determining coverage under the Gas Code, the 'hypothetical new entrant' test is the correct benchmark for determining contestable prices and whether a firm is exercising market power.

As indicated earlier, the Commission engaged NERA to provide advice on the HNET. While NERA agrees that the HNET is one benchmark to evaluate whether a firm's prices are indicative of the exercise of market power it was critical of the manner in which NECG applied the test. In particular, it was critical of NECG's use of firm-specific volumes (volumes flowing through the MSP) rather than market volumes (MSP volumes plus EGP).

NERA defines the hypothetical new entrant test as the maximum price that an incumbent could charge if there was a credible threat of new entry. In other words what is the maximum price that consumers would be willing to pay the incumbent if they had the option of negotiating as a coalition with a new entrant. The HNET is an attempt to derive a hypothetical 'competitive' market price for an industry that is not competitive.

In its submission, NECG concluded that the revenue requirement of a hypothetical new entrant is about $89m, in contrast to the Commission's proposed revenue requirement of $59m in its Draft Decision. NECG states that EAPL's current tariff of $0.66/GJ (Moomba to Sydney) is more consistent with the HNET revenue stream than the Commission's proposed tariff of $0.43.

Underlying NECG's conclusion is the assumption that the HNET tariffs should be based on current volumes for the MSP. Of importance in this regard is that MSP volumes are at a low point following a loss of volumes to the EGP.

NERA was critical of this on the basis that if the HNET, as proposed by NECG, was applied prior to the entry of the EGP, then the HNET tariffs should be lower than today's tariffs given the difference in volumes. NECG's approach creates an anomaly as the entry of another pipeline should not result in the HNET price increasing (competition does not lead to higher prices).

NERA argues that it would be more efficient for one pipeline to supply the total NSW/ACT demand than two pipelines (the MSP and EGP). Hence, the correct methodology for applying the HNET would be to determine the costs of constructing an optimal pipeline to supply the whole market and use total market volumes (not firm-specific volumes) to determine tariffs.

NERA concludes that the hypothetical new entrant price is about $0.51/GJ, which is the maximum price that would be expected to be observed in a competitive market. This tariff is significantly below EAPL's current tariffs ($0.66/GJ for Moomba to Sydney), which is equivalent to an increase over the HNET tariff of about 30 per cent. NERA further concludes that the application of the HNET supports the assertion that EAPL is exercising market power and charging monopoly prices. The HNET tariff of $0.51 is based on the operating costs originally proposed by EAPL in 1999 (around $12m per annum). In its revised access arrangement EAPL has proposed operating costs of around $23m per annum. The Commission has requested EAPL to provide evidence to support the higher level of costs. Even if the HNET tariff is based on the higher level of reasonable operating costs, NERA's conclusion that EAPL is exercising market power would still stand.

Regulatory compact approach

An alternative approach to the HNET discussed by NERA in its report is the regulatory compact approach. Under this approach the regulatory compact price could deviate from the new entrant price (either above or below) at any point in time, provided that over the life of the asset the firm does not recover more than its costs of supplying services. An approved access arrangement under the Code would constitute a regulatory compact. Given the history of the MSP – Commonwealth ownership before 1994 and the subsequent sale to EAPL – the Commission questions whether in fact a regulatory compact, as described by NERA, existed prior to the introduction of the Gas Code.

5. Conclusion

In its submission NECG was critical of several aspects of the Commission's application of the Code in deriving reference tariffs. These included: inconsistent use of asset lives when calculated the value of the initial capital base and forward depreciation; understatement of the optimised replacement costs; underestimation of risk; use of an effective rather than a statutory tax rate; exclusion of a return on working capital; and deducting accumulated deferred taxes from the value of the asset base.

This submission considers some of the issues raised by the NECG. Those issues and others will be further considered by the Commission in reaching its Final Decision on EAPL's proposed access arrangement. The comments in this submission are not to be construed as pre-empting the Commission's Final Decision.

NECG was also critical of the use made by the NCC of the reference tariffs proposed by the Commission in its Draft Decision on EAPL's proposed access arrangement to conclude that EAPL is exercising market power and charging monopoly prices. NECG suggested that a more appropriate benchmark is the 'hypothetical new entrant test' (HNET). In this regard the Commission engaged the services of NERA to critique the NECG report, in which NECG concluded that EAPL's current tariffs are consistent with the HNET. While NERA agreed that the hypothetical new entrant test may be an appropriate benchmark to gauge monopoly pricing in some circumstances, it was critical of the manner in which the NECG applied the test to the MSP. NERA concluded that the HNET tariff is $0.51/GJ, which is significantly below EAPL's current tariffs and is evidence that EAPL is exercising market power.