Western Australia

Economic Regulation Authority

SUBMISSION TO PRODUCTIVITY COMMISSION

REVIEW OF THE GAS ACCESS REGIME DRAFT REPORT

April 2004

Table of Contents

The Economic Regulation Authority of Western Australia

The Economic Regulation Authority of Western Australia (Authority) was established on 1 January 2004 to, among other things, function as the Relevant Regulator under the Gas Pipelines Access (Western Australia) Act 1998 (GPAA). The GPAA gives effect to the National Third Party Access Code for Natural Gas Pipeline Systems (Code) which is appended as Schedule 2 to that Act. The role of the previous Western Australian Office of Gas Access Regulation (O*ff*GAR) is now performed by the Gas Division of the Authority.

Draft Report on the Gas Access Regime

The Authority has given consideration to the Draft Report on the Gas Access Regime by the Productivity Commission (Commission) released on 15 December 2003 and in this submission offers the comments set out below to assist the Commission in its finalisation of that report.

The Authority, as a Relevant Regulator under the Gas Pipelines Access (Western Australia) Law, does not offer any particular view on whether an industry should be subject to access regulation or not or on the stringency of the regulatory regime to be imposed. The Authority is not, therefore, seeking to advocate in this submission any particular outcome by the Commission in its review of the Gas Access Regime. The Authority is, however, of the view that the findings and recommendations by the Commission should be based on an objective assessment of the issues involved. The Authority is also of the view that the Commission should pay particular attention to the practicality of implementing any of the changes it is considering to recommend. It is noted that in making changes, attention needs to be given to consistency across all elements of the regime as well as clarity as to the roles of the individual authorities involved.

Overview

The Authority considers that the aim of the Commission's review of the Gas Access Regime appears to have largely been addressed. This aim being to identify and recommend improvements to the Gas Access Regime so that it will provide for an appropriate balance of the interests of relevant parties within a framework that will foster efficient investment in pipeline infrastructure and facilitate the development of competition in gas markets upstream and downstream of that infrastructure.[1]

The Authority understands that, in summary, the thrust of the Commission's findings and recommendations are as follows:

- The Gas Access Regime would continue as an industry-specific regulatory regime.

[1] Terms of Reference issued by the Commonwealth Treasurer.

- The inclusion of an overarching objects clause directed towards economically efficient outcomes is recommended.
- Coverage would continue to be decided by elected authorities giving appropriate weight to the public interest.
- An alternate form of regulation involving price monitoring would be available to be applied where appropriate.
- Where discretion is involved by the Regulator in approving an access arrangement containing a Reference Tariff some subjective elements for consideration by the Regulator are recognised.
- The objectives for a complying access arrangement and its Reference Tariff Structure are to be reduced in number.
- Effective ring-fencing of the Service Provider is to be retained for both the price cap and the proposed price monitoring form of regulation.

Comments on Findings and Recommendations

In this section, the Authority offers comments, where appropriate for it to do so, on draft recommendations and includes comments on some related draft findings. These comments focus primarily on matters of interpretation and implementation.

In the section following this section, the Authority provides some responses to the information requests made in the Commission's draft report.

DRAFT RECOMMENDATION 5.1

The following overarching objects clause should be inserted into the Gas Access Regime:

> ***To promote the economically efficient use of, and investment in, the services of transmission pipelines and distribution networks, thereby promoting competition in upstream and downstream markets.***

If an objects clause is to be inserted that seeks to promote the economically efficient use of, and investment in, the services of transmission pipelines and distribution networks, then particular care would need to be exercised to ensure that such an objects clause is consistent with the remaining wording of the regime, particularly the Code. For example, the Relevant Regulator may find this clause to be in tension with other parts of the Code such as s.8.10 and s.8.11, which in their present form countenance outcomes beyond the economically efficient use of or investment in pipelines and pipeline networks.

DRAFT RECOMMENDATION 5.2

With the implementation of draft recommendation 5.1, the following objectives in the preamble to the existing legislation and the related objectives in the introduction to the Gas Code should be deleted:

(a) ***facilitates the development and operation of a national market for natural gas***

(b) ***prevents abuse of market power***

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

(d) ***provides for rights of access to natural gas pipelines on conditions that are fair and reasonable for the owners and operators of gas transmission and distribution pipelines and persons wishing to use the services of those pipelines***

(e) ***provides for the resolution of disputes.***

The proposed deletion of related objectives b), d) and e) in favour of the overarching term appears to significantly focus the application of the Code on economic efficiency. Again this raises important questions of consistency and the possible need for extensive further changes to avoid tension between the various provisions of the regime and the objects clause.

One consequence of the greater emphasis on economic efficiency would be a loss of a feature of the current regime which in objective (d) emphasises a right of access under fair and reasonable terms. This existing feature of the Code recognises the interests of users, some of whom may choose to use capacity in a manner that may not be seen as strictly economically efficient, e.g. a user holding unutilised capacity for its own use on a contingent basis. The current regime places up front the fundamental question of needing for every element of the regulatory outcome to strike an appropriate balance between the interests of all relevant parties.

It is, however, understood that coverage tests will continue to focus on pipelines that are natural monopolies where the potential for abuse of market power is a primary concern.

There is also an issue concerning resolution of access disputes between Prospective Users and a Service Provider and various appeal provisions which are included to deal generally with disputes over coverage and regulatory decisions. Further detailed consideration may be necessary to ensure the effectiveness of these provisions if the regime is to rely primarily upon an economic efficiency imperative.

DRAFT RECOMMENDATION 5.3

The following elements of s.2.24 of the Gas Code should be deleted:

(a) ***the Service Provider's legitimate business interests and investment in the Covered Pipeline***

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

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

(f) ***the interests of Users and Prospective Users***

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

The Authority recognises that the two matters that the Commission recommends to be retained, respect for existing binding contract rights and not adversely impacting on safety and reliability, are both important considerations in the assessment of a proposed access arrangement.

In proposing the deletion of the elements listed above, the Commission presumably envisages that the Regulator would, in approving a proposed Access Arrangement, place significant weight on the proposed objects clause relating to economic efficiency. The Regulator would thus be charged to conduct a public process under the Code giving consideration to stakeholder's interests with particular attention being given to economically efficient outcomes.

If the Commission were to reconsider its draft position and reinstate one or more of the elements of s.2.24, then to maintain a proper balance between competing interests the Commission would need to consider the retention of all of these elements.

DRAFT RECOMMENDATION 7.1

Section 8.1 of the Gas Code should be replaced with the following:

> ***The relevant regulator must have regard to the following principles when approving a reference tariff or reference tariff policy:***
>
> ***(a) that reference tariffs should:***
>
> > ***(i) be set so as to generate expected revenue across a service provider's regulated services that is at least sufficient to meet the efficient long-run costs of providing access to those services***
> >
> > ***(ii) include a return on investment commensurate with the regulatory and commercial risks involved***
> >
> > ***(iii) generate revenue from each service that at least covers the directly attributable or incremental costs of providing the service.***
>
> ***(b) that reference tariff structures should:***
>
> > ***(i) allow multi-part pricing and price discrimination when it aids efficiency***
> >
> > ***(ii) not allow a vertically integrated service provider to set terms and conditions that disadvantage competitors of its associated businesses in upstream or downstream markets, except to the extent that the cost of providing access to these competitors is higher.***
>
> ***(c) that reference tariffs should be set so as to provide incentives to reduce costs or otherwise improve productivity.***

It is noted that the first paragraph of the proposed new s.8.1 subtly shifts the emphasis from principles that should apply generally to the design of a Reference Tariff and Reference Tariff Policy under this Code to what the Relevant Regulator must have regard to in approving a Reference Tariff and Reference Tariff Policy. The Authority considers that the proposed wording more clearly states the matters of relevance to the Relevant

Regulator and reduces possible ambiguity in this regard. As a practical consideration in reducing the scope for dispute over the design of proposed access arrangements, those preparing such proposals should however continue to also understand that under the Code they are under a similar clear and unambiguous obligation.

It is also noted that the Commission's draft recommendation for s8.1 no longer makes provision for the Relevant Regulator to determine the manner in which the proposed objectives can best be reconciled or which of them should prevail. The reason for this omission is unclear, however, presumably the Relevant Regulator would be guided by the objects clause in reconciling any tension between the recommended objectives.

It is evident that the proposed new s.8.1 moves away from the theme of a competitive market for services, as expressed in existing s.8.1(b) and s.8.1(f), towards a greater focus on revenue from regulated services, whether in the future these services happen to be price monitored or subject to a reference tariff price cap. This move can be expected even though the proposed new s.8.1(c) replacement for existing s.8.1(f) retains the concept of Incentive Mechanisms that are capable, if carefully designed, of motivating the Service Provider to behaviour that is most likely to bring about efficiencies and service offerings that parallel those in a more competitive setting. It is noted, however, that the new s.8.1(c) expresses the incentive mechanism in only the dimension of cost reductions and productivity gains, as opposed to a more comprehensive approach that would also seek to safeguard service quality and increased reliability.

The recommended s.8.1 principles appear to invite a continuing intrusive regulatory approach for pipelines and networks subject to the more stringent form of regulation envisaged under the new coverage criteria. Further, the requirements to at least meet efficient long-run costs and to at least cover attributable or incremental costs of providing each service, would seem to necessitate an in-depth and auditable analysis of the Service Provider's business and of its strategy for the future regulatory period.

It is noted that the Relevant Regulator in considering the approval of an access arrangement is now to have regard to the setting of Reference Tariffs that generate expected revenue and that provide a return on investment commensurate with both regulatory and commercial risks involved. The specific reference to regulatory risk implies that such risk is a matter of relevance which is at variance with the view held by some practitioners and academics that regulatory risk is fully diversifiable and not relevant to the setting of commercial rates of return.[2]

At present the usual practice of regulators is to have regard to market outcomes in relation to rates of return which essentially give less weight to diversifiable risk factors and greater weight to non-diversifiable or systematic risk factors in assessing an adequate rate of return on equity for regulatory purposes. This current approach gives recognition to the fact that investors have the opportunity to accept rates of return for individual investments that are acceptable in terms of holding those investments within a diversified

[2] Refer Institute for Research in International Competitiveness, "The Review of Rate of Return Methodologies and Practices", September 2003.

portfolio of investments with a corresponding reduction in overall risk. The methodology of choice to determine the return on equity that delivers an appropriate level of compensation has been the capital asset pricing model (CAPM).[3]

Specifically, the Commission might consider whether the regulatory risk it has in mind is something of a generic nature related to simply being a Covered Pipeline under the Code or of a particular nature related to both the circumstances of the individual Covered Pipeline and its interaction through the Code with a particular Relevant Regulator at a particular point of time.

At present individual project risks for which a mitigation approach can be expressed in terms of a payment to shift that risk to others, typically an insurance provision, may be accommodated as a cost to operations in the cash flow that forms part of the required revenue calculation. The financial consequences of other project specific risks that may or may not eventuate during an access arrangement period might also be accepted by the Regulator as a cost against cash flow for the supply of regulated services at the time those consequences are actually realised. It would be helpful for the Commission to clarify whether adoption of the proposed wording of the new s.8.1(a)(ii) is intended to bring about any specific change in these practices.

The proposed new s.8.1(b)(i) is seen as providing a slightly more flexible approach to Reference Tariff structure than does the current s.8.1(e). The Authority believes that multi-part pricing and discrimination by class of User with the objective of having an efficient Reference Tariff structure is already available under the Code, even to the extent of enabling Prudent Discounts in individual situations. The increased flexibility of the proposed new s.8.1(b)(i) in relation to explicitly enabling price discrimination needs to be weighted against the need to make provision for an appropriate balance of charging as between different classes of Users including Prospective Users as distinct from existing Users.

To avoid ambiguity it is suggested that the proposed wording of item 8.1(b)(ii) be clarified stating that any higher price of providing access to competitors would be linked to the higher efficient cost of providing such access.

The Authority also considers that it would assist stakeholders if robust definitions of “efficient long-run costs” under the proposed new s.8.1(a)(i), and of “regulatory and commercial risks” under the proposed new s.8.1(a)(ii) could be clearly enunciated. Clarifying what cost components may or may not be included and what would be a relevant means of determining an efficient level of long-run cost, may reduce what appears to be considerable scope for debate and potential for appeal. Clarifying what is meant by regulatory risk in this context and what factors might be relevant when considering how to gauge and express that risk in the context of assessing the rate of return may further help to reduce uncertainty.

[3] ibid

DRAFT RECOMMENDATION 7.2

The Gas Code's competitive tendering provisions should be simplified to make them more flexible and less costly.

The Authority believes that the tendering provisions of the Code can be of value in fostering infrastructure investment decisions, particularly in embryonic markets and frontier situations, with greater flexibility for setting an approved access arrangement for third party access. The Authority would support making the provisions better suited and less onerous, including where proponents may believe that a price-monitoring arrangement would be part of an acceptable tender.

DRAFT RECOMMENDATION 7.3

The Gas Code should be amended to ensure that regulators' requirements for establishing and maintaining information are standardised across jurisdictions and are as close to existing gas industry accounting or record keeping practices as possible.

The Authority continues to support initiatives underway through the Regulators Forum to settle on suitable standardised information requirements.

The proposed advent of a price-monitoring regime as one of the regulatory regimes available under the Code suggests that this effort by regulators should be expanded to include requirements appropriate also for that regime. Draft Recommendation 8.2 provides that the price-monitoring regime include ring-fencing and thus it will place similar obligations on regulators and information requirements for Service Providers as exist now for regulators to agree and effectively oversight continued compliance with that obligation for separation of businesses.

It is noted that Draft Recommendation 8.3 runs counter to the thrust for standardisation in that it would see the NCC making determinations on a case-by-case basis for information requirements to be complied with under price-monitoring and that the information base could be performance orientated not just financial.

It is also noted that the information requirements necessary for the approval of an initial access arrangement under the existing Code are likely to remain somewhat different from those needed to substantiate a routine revision of an access arrangement that is already in place. Also, any unusual variants proposed to an access arrangement are likely to warrant specific information that addresses that particular circumstance.

The calls for information on a routine basis during an access arrangement period, as noted under Draft Finding 7.3, have the potential to add to reporting costs at that time, but could forestall an even more strenuous effort being needed by the Service Provider to present and verify historical cost and performance data for a scheduled revision of the arrangement. It is conceivable that price-monitoring will require at least annual reporting of both price and performance data.

Information asymmetry between the Service Provider, the Relevant Regulator and other stakeholders will necessarily be exacerbated with any standardised requirements, as particular information relevant to an individual situation would be excluded.

The success of current incentive mechanisms to foster cost efficiencies and to lower costs towards long-term efficient levels, in spite of that asymmetry, is yet to be demonstrated. Incentives do however need to become better tailored to achieving a comprehensive optimal outcome with sustainable cost savings secured while also sustaining market growth and improved customer service and supply reliability. It would seem sensible for a holistic view to be taken of incentive mechanisms together with related information requirements when further efforts are expended on standardisation of information requirements.

DRAFT RECOMMENDATION 7.4

Section 3.16 of the Gas Code should be amended so that any expansion of a covered pipeline will be treated as part of the covered pipeline, unless the service provider nominates otherwise and the regulator agrees.

While this draft recommendation runs counter to the general thrust for all coverage decisions to be made by an elected decision maker with NCC advice, in most if not all cases of progressive expansion of a pipeline system it could prove to be a worthwhile simplification of the Code process. Greater consistency with other coverage arrangements might be achieved if this simplification were the default adopted unless specifically excluded as part of the original or a subsequent coverage decision.

DRAFT RECOMMENDATION 8.1

The Gas Access Regime should be amended to provide for a lighter handed form of regulation whereby the application of the alternative regulation involving an access arrangement with reference tariffs would only occur in the more extreme circumstances. The lighter handed alternative should be a monitoring regime. It is important that the monitoring regime not develop into an intrusive and costly form of regulation.

The Authority sees that, as a regulatory agency with responsibilities under the Code, it is only appropriate for it to comment upon the implications for the Relevant Regulator of information requirements necessary to implement any proposed price-monitoring regime.

In this respect, it is relevant to comment on Draft Findings 7.5 and 7.6 as these draft findings have been used as part of the case to support the proposed alternative regime. In particular, Draft Findings 7.5 and 7.6 make comment in relation to costs of regulation under the current Reference Tariff price cap regime.

Draft Finding 7.5 states that there is a high potential for regulatory error when approving Reference Tariffs, and concludes that seeking additional information from Service Providers and through further studies by consultants is unlikely to reduce uncertainty significantly. The Authority sees it as an unavoidable responsibility for the Regulator to gain an appreciation for the basis of proposed Reference Tariffs at least sufficient for it to provide a competent and robust assessment as to whether the proposal complies with the Code. Inevitably, information asymmetry and the potential for commercial bias by the

Service Provider are concerns in reaching that appreciation based solely upon the information proffered by the Service Provider.

In the absence of information from the Service Provider, sufficient to substantiate as reasonable the assumptions the Service Provider has had to make in many aspects of its forecast of cost and market growth underlying its proposed Reference Tariffs, the Regulator is left with little alternative but to seek for itself a sound basis for accepting or rejecting the assumptions of the Service Provider.

The result of such further enquiry, assisted as necessary by the engagement of suitably qualified consultants, may produce more reliable assumptions. Equally, such further enquiry also provides a means of assessing the basis of the assumptions proffered by the Service Provider.

It seems to the Authority that the adoption of incentive mechanisms designed to drive towards and reveal efficient costs as well as to promote efficient market growth is likely, over time, to reduce the requirement for regulators to make sometimes intrusive enquiry of the Service Provider and to seek professional assessments by independent consultants as to these matters. In the meantime, the Regulator will need to pursue the requirement of the Code to adequately substantiate as reasonable the forecasts of costs and market growth assumed by the Service Provider.

Draft Finding 7.6 suggests that the costs involved in the Reference Tariff price cap regime, especially in relation to market impact, is justification for there to be some alternative and less costly approach. This suggestion, in highlighting market impact, would seem to go well beyond the obvious costs of conducting the current regulatory process. The Authority is however concerned, on the cost front at least, that the costs for conducting an effective price-monitoring regime should not be underestimated.

The proposed alternative regime would appear to still require the Regulator to be in an informed position concerning ring-fencing, price discrimination for associates, and the incidence of failure to negotiate in good faith access for individual Users or Prospective Users. The public might also reasonably expect the Regulator to be in an informed position concerning the prices and associated terms and conditions that are offered by the Service Provider and alert to discriminatory pricing practices that could operate counter to the principal economic efficiency objective. The Regulator will also have to be adequately informed in order to comply with the proposed restriction that only factual information is to be reported by it.

The Authority will seek to contribute constructively on these aspects to the refinement of the information and other reporting requirements that any such price-monitoring regime is likely to involve for it to be seen as effective.

DRAFT RECOMMENDATION 8.2

The monitoring form of regulation to be implemented under the Gas Access Regime should have the following features:

- ***a third party access policy formulated by the service provider***

- ***separation of pipeline operations from associated businesses in upstream and downstream markets***
- ***public disclosure of information by the service provider (which would be well short of the 'access arrangement information' currently required under the Gas Code)***
- ***scope for the service provider to adopt, at its discretion, additional pro-competitive features, such as a code of conduct.***

The Regulator's role under the price-monitoring regime proposed is not, as yet, well defined. This role might at this stage be taken to span anything from holding casual observer status through to that of engaged advocate for Users and Prospective Users in the pursuit of economically efficient outcomes.

The requirement for ring-fencing, and its accompanying concern for discrimination on price and other terms for contracts to associates, suggests more than a casual observer status at least on that aspect. The Authority sees that to be efficient and effective, it may be important to interface this monitoring form of regulation with other legislated requirements for consumer protection, trade practices, etc. It has, for example, some opportunity to interface at the residential and small commercial user end of the market with the role of an energy ombudsman. The Authority suggests that consideration be given to producing guidelines within the Code for both the Regulator's and the Service Provider's roles under any such price-monitoring regime.

DRAFT RECOMMENDATION 8.3

In making a coverage decision to apply the monitoring regime, the National Competition Council should specify what information the service provider is required to disclose to the relevant regulator. Implementation of the information disclosure requirements would involve:

- ***the regulator focusing more on trend performance, including in relation to profitability***
- ***reporting and monitoring after the event, without any need for prior endorsement by the regulator***
- ***the regulator particularly monitoring cases where access negotiations have been unsuccessful.***

The information disclosure specification provided in Draft Recommendation 8.3 is recognised as preliminary and indicative in nature. It does, however, add consideration of Service Provider profitability on an after the event basis.

The Authority notes that monitoring could be of little value in the pursuit of the primary economic efficiency objective unless Users were also to be assured that ring-fencing was effective against transfer pricing, for example, through the Regulator approving service agreements with associates and through the availability of relevant and unbiased comparisons with the profit performance of kindred businesses.

It is noted, however, that as far as the requirements of the Service Provider to provide information is concerned, this is left to the NCC to determine. The Authority believes that these matters would need to be spelt out in the Code as far as the role of the Regulator is concerned.

DRAFT RECOMMENDATION 8.4

The relevant regulator should collate and publish annually the information disclosed by a pipeline under the monitoring regime. Any commentary made by the regulator should be of a factual nature only.

The Authority foresees some difficulty in ensuring compliance with a requirement for factuality in any commentary. The Relevant Regulator may in many cases not be the source of, or have access to, relevant information and, without a mandate for conducting diligent enquiry, will not be able to establish factuality to reasonably satisfy such a requirement.

It is noted that, from Draft Finding 8.2, the Regulator may be left to rely upon the declaration of the Service Provider as to factuality of the information it supplies. This may weaken the effectiveness of regulation under any price-monitoring regime, given that the commercial interests of the Service Provider are hardly likely to provide strong incentives for frank disclosure.

It may be more helpful if a practical set of guidelines was placed in the Code for dealing with the role of the Regulator in respect of conveying to the public matters related to any price-monitoring regime.

DRAFT RECOMMENDATION 9.1

The Gas Access Regime should be amended so that the National Competition Council, on request from a potential pipeline investor, can provide a binding ruling on coverage. A binding ruling in favour of lighter handed monitoring should be for the same duration as the minimum period for lighter handed monitoring under the regular coverage test (five years). A binding ruling that a pipeline would not be covered should apply for 15 years. These rulings should not be revoked unless the information relied on by the National Competition Council is proven to be false or intentionally misleading.

Draft recommendation 9.1 for a binding ruling from the NCC is not consistent with Draft Finding 12.5 that states that the ultimate responsibility for coverage should continue to reside at Ministerial level. It is noted that Draft Recommendations 6.5, 11.2 and 12.1 and Draft Findings 12.3 and 12.4 all deal with the making of a recommendation on coverage.

DRAFT RECOMMENDATION 10.1

Section 7.1 of the Gas Code should be amended such that a service provider entering an associate contract for the supply of services at the reference tariff must notify the relevant regulator, but is not required to seek authorisation.

Draft recommendation 10.1 appears to apply only to an associate contract for transportation services at the Reference Tariff and therefore it is presumed that it is intended for the existing authorisation arrangements to continue to apply both for contracts for the supply of transportation services at other than the Reference Tariff and for all other types of associate service contracts.

It is noted that, even in the limited case of associate contracts for supply at the Reference Tariff, potential discrimination may arise in favour of associates through changes in terms and conditions that may attach to an associate contract for supply of the Reference Service as compared with independent third party contracts.

DRAFT RECOMMENDATION 11.1

The Gas Access Regime should be amended, whereby the regulator would:

- ***be able to extend the period for approval of an access arrangement by two months only once***
- ***have the discretionary power to backdate reference tariffs.***

The Authority is concerned at the time taken to conduct some regulatory processes and the further time that has on occasion been consumed by exercise of judicial review. The Authority expects these processes to become less time-consuming now that the first round of approvals is almost completed nationally and evidence is gathering that scheduled revisions of access arrangements are being handled expeditiously.

The Authority is concerned that placing limitations that are too severe on timing for some steps of the process could lead to regulators faced with inadequate information thereby deciding not to approve an arrangement that with the benefit of additional information might be approved as complying. This hazard aside, pressure on timing needs to be felt across all stakeholders leading to strict timing on close off of submissions, including those from the Service Provider, despite the Regulator's concern that natural justice considerations be uppermost in management of the consultation process steps. An alternative may be for successive extensions of 2 months to continue under s.2.22 and s.2.44, but with the Regulator publishing reasons on each occasion.

This draft recommendation is understood to seek a balance between imposing deadline obligations on the Regulator and back-dating of a decision to, if necessary, address a possible commercial interest of the Service Provider or of other stakeholder(s) in protracting a regulatory outcome.

The Authority notes that the recommendation is for the discretion to back-date to reside with the Regulator. The Authority would presume that any decision to back-date would firstly be foreshadowed by the Regulator to all stakeholders accompanied by reasons for this proposed action, followed by a brief but sufficient opportunity for the relevant stakeholder(s) to resolve the issue involved, before an order implementing the back-dating was made.

DRAFT RECOMMENDATION 11.2

The Gas Access Regime should be amended, whereby the National Competition Council's recommendation on coverage would be agreed in the absence of a Ministerial objection within 21 days.

The Authority offers no comment on this coverage matter, other than to note that it is consistent with coverage decisions to ultimately reside with the relevant Minister.

DRAFT RECOMMENDATION 11.3

The Gas Access Regime should be amended whereby the 'further final decision' should be removed from the approval process for access arrangements.

Eliminating the further final decision process will deny the Service Provider from submitting a complying revised access arrangement in response to the final decision. In effect, this will provide only one opportunity for the Service Provider to understand the draft decision of the Relevant Regulator and to make a response to it, before that Regulator may find that response unsatisfactory and proceed to draft and approve its own access arrangement.

Experience in Western Australia is that the making of a further final decision provides a fair opportunity for the Service Provider to respond to the Regulator's final decision. It also provides for the Regulator to consider that response. This process is regarded as an important step in clarification of points of difference and, in the view of the Authority, contributes to natural justice being afforded to the Service Provider in the event that the Service Provider does not find the final decision to be acceptable. This is believed to be important since in the event that the Service Provider's revised access arrangement continues to not be in compliance with the Code, the next step under the Code is essentially a last resort whereby the Relevant Regulator must unilaterally draft and approved its own access arrangement.

This further final decision process gives both the Relevant Regulator and the Service Provider the opportunity to deal with aspects in the final decision that, despite conscientious effort, remain open to interpretation or open to an alternative response. It does not, in the view of the Authority, raise the prospect of any substantial revisit to the fundamentals of the final decision.

In a situation where an appeal appears to be the likely ultimate course, in the view of the Authority it is incumbent on the Relevant Regulator to provide a clear, concise and exhaustive record of the consultation, information and decision-making considerations that have been involved in the regulatory process to that point.

As any merits-based appeal is to remain subject to the information that was before the Regulator at the time of its most recent decision in that case, the further final decision step enables the Service Provider a second opportunity to put information before the Relevant Regulator and into that record. Decisions that go to appeal might well be expedited in the appeal as a consequence of the clarification of issues and information before the Relevant Regulator that is delivered by a further final decision step.

DRAFT RECOMMENDATION 11.4

The Gas Access Regime should be amended so regulators can specify a date by which the service provider must submit proposed amendments to an access arrangement.

The Authority supports an amendment to s.2.15A of the Code to correct this deficiency.

DRAFT RECOMMENDATION 11.5

Limitations on the grounds of appeal under s.39 of the Gas Pipelines Access Law should be removed to allow a full merits review on access arrangements drafted and approved by the regulator.

The Authority accepts that a full merits-based appeal may be appropriate where the Relevant Regulator has drafted and approved its own access arrangement.

DRAFT RECOMMENDATION 11.6

The scope of material that can be introduced to the appeal body under s.38 of the Gas Pipelines Access Law should be restricted to material that has already gone before the primary decision maker.

The Authority supports this Draft Recommendation 11.6 with respect to any merits-based appeal.

DRAFT RECOMMENDATION 12.1

The agency responsible for making recommendations on pipeline coverage decisions (currently the National Competition Council) should be separate from the regulator responsible for administering the terms of pipeline access. The agency that recommends coverage of a pipeline, should also be responsible for recommending the form of regulation to apply to the pipeline.

The Authority supports Draft Recommendation 12.1 in respect of the agency making recommendations on coverage being separate from the Relevant Regulator under the Code. The Authority has not expressed a view concerning the appropriateness or otherwise of the provision of an alternative form of regulation proposed to be made available under the Code.

Information Requests

The Commission has invited further information and comment on the following matters:

- ***appropriate ways for access seekers to demonstrate 'best endeavours' in negotiating access (chapter 6)***

  The Authority believes it will remain extremely difficult, if not impossible, for an access seeker to demonstrate best endeavours in negotiation with any Service Provider that is outside the regulatory regime of the Code. Even under the Code, it may still be difficult if the applicable regime were a price-monitoring scheme that provides no clear indication as to price and as to terms and conditions for the nature of the service being either sought or offered.

Under a price-monitoring regime, the question as to whether the listed price etc. is fair and reasonable could remain un-addressed without some independent regulatory process to publicly provide an assessment. An alternative may be to undertake a benchmark assessment, but this suffers from acknowledged difficulties with establishing comparable situations and appropriate benchmarks for best practice.

Aside from the access seeker being able to justify its negotiating stance to be based on reasonable price, terms and conditions, some documentation of the negotiating process would also be necessary to demonstrate best endeavours.

It is noted that best endeavours by an access seeker may also be seen in relation to potential discrimination by the Service Provider between associates and third parties. In a price-monitoring regime it may not be feasible for the Regulator to authorise contracts with associates if there are no relevant benchmarks established, and thus the Regulator may not be in a position to determine when circumstances of discrimination face an access seeker along with the range of other concerns about conducting best-endeavours good-faith negotiations.

- ***its proposed framework for who can apply for coverage and revocation of coverage (chapter 6)***

  The Authority makes no comment on this policy aspect of coverage.

- ***the specific nature of the nonfinancial information that service providers could maintain and provide that is essential for regulators in understanding the derivation of elements of a proposed access arrangement and for forming an opinion as to its compliance with the Gas Code (chapter 7)***

  Typically non-financial information essential for regulators in understanding the derivation of elements of a proposed access arrangement and for forming an opinion as to its compliance with the Code includes any basis used by a Service Provider in allocating joint costs as between:

  - different services, such as reference services and non-reference services;
  - a regulated service and non-regulated service;
  - a Service Provider and associate companies.

  The basis for allocating joint costs is at the discretion of the Service Provider and can include a wide range of parameters including throughput, maximum daily quantity, number of employees etc.

  Clearly the basis used for allocating joint costs impacts on the reasonableness of the costs attributed to reference services and without such non-financial information a regulator is not able to make informed judgements relating to the reasonableness of reference tariffs or ring fencing arrangements.

Since the choice of a cost allocation basis is at the discretion of a Service Provider and since there is no discrete limit to the types of basis that may be selected by a Service Provider there is no standardised list of non-financial parameters.

Regulators under the Code appear generally to have been reluctant to resort to section 41 powers to obtain information necessary for the Regulator to form an opinion as to compliance, preferring voluntary provision from the relevant stakeholder. The Authority expects that preference to continue, but pressure for expedited processes and strict adherence to timelines for submissions could shift the balance towards compulsion through s.41 for non-financial as well as financial information.

It is clear that even s.41 may be ineffective if no historical actual information is recorded. Since an access arrangement is a forward looking document presenting information for the projected access arrangement period, the basis for allocating joint costs is itself merely an estimate.

Verification of projected data against actual historical information may be further frustrated if there is outsourcing of work by the Service Provider to associate asset management companies or to other contractors and inadequate records are kept by either the Service Provider or associate companies.

- ***the possible implications of introducing use-it-or-lose-it rules for unutilised contracted capacity. If such rules were introduced, how should owners of contracted capacity be compensated? (chapter 7)***

The Authority is aware that unutilised capacity may be sold by a Service Provider on a spot interruptible basis with all proceeds being retained by the Service Provider. Such a regime encourages improved utilisation of the pipeline while not denying users with contracted capacity the right to trade any spare capacity on the secondary market.

More stringent "use-it-or-lose-it" rules may however have undesirable consequences and any such arrangements would require careful consideration. To the extent that a tariff structure appropriately compensates the Service Provider for the capital component required to provide the contracted capacity, it seems appropriate to give the contracting party maximum opportunity to decide in what manner it decides to use the service that it has obtained a contract right to take. That decision might be to on-sell the capacity or hold it as contingent capacity for its own use. It is only where capacity would be left unutilised on the day that a right might be exercised. This may be achieved by use of an interruptible spot contract offered by the Service Provider.

While the rights of holders of contracted capacity can be better facilitated by the promotion of secondary market mechanisms, the use of an interruptible spot contract by a Service Provider would only be necessary where the holder of contracted capacity explicitly chooses not to use the secondary market.

One adverse implication of introducing a more stringent "use-it-or-lose-it" rule could be that foundation customers are discouraged about entering contracts because the on-sale of unutilised capacity from those contracts might be offered to other users and potential competitors at a price less than that paid by the foundation customer.

The facilitation of expansion of pipeline systems to avoid the holders of underutilised contract rights effectively being able to exploit their near-monopoly position as suppliers of capacity would seem a more constructive alternative.

The Authority thus does not suggest any means of administratively depriving a capacity holder of its contracted rights through some stringent form of "use-it-or-lose-it" rule.

- ***how ring fencing and associate contract requirements could be implemented under the proposed monitoring regime that does not involve the prescription of reference tariffs (chapter 8)***

  The Authority considers that some form of benchmarking might need to be devised to enable any price-monitoring regime to have any hope of pursuing economically efficient outcomes. Assessment of associate contracts and the vigilance necessary to contain the opportunities for transfer pricing through service and management contracts will be severely degraded without some means of inquiring into and assessing efficient costs against benchmark service levels.

- ***what data items should be reported under the proposed monitoring regime, the level of disaggregation that should be involved and how data should be presented (chapter 8)***

  The Authority is open to working with other regulatory agencies and the NCC or other organisation, should that be necessary, to devise a set of information reporting requirements for any price monitoring or other regime under the Code.

- ***introducing a Gas Code provision for a dedicated truncation premium. In particular, the Commission welcomes suggestions on the most practical way to implement such a premium (chapter 9)***

  The Draft Report analyses in some depth the proposition that under a Reference Tariff price cap regime the Service Provider may be prevented from earning high returns if the project is successful (that is, if returns are well above the forecast level) yet bears the cost if the project is unsuccessful (that is, if returns are below the forecast level). This limiting of upside returns in the presence of downside risk that may be associated with price cap regulation is referred to as asymmetric truncation.

  The Draft Findings 9.6 and 9.7 suggest that there is a detrimental investment distorting effect of such asymmetric truncation of returns and that some form of truncation premium should be given as compensation to all Covered Pipelines. The Commission has therefore invited suggestions on the most practical way to implement such a premium.

  However, given that the Code only applies to natural monopoly infrastructure there is a real need to be clear on whether such businesses actually face any appreciable downside risk. This is not to suggest that some new greenfield pipeline investments would be free of downside risk, but in such specific circumstances it is also appropriate to ask whether such risk may be better addressed through some form of Government guarantee or subsidy.

In considering asymmetric truncation, it is also important to be clear that the Gas Access Regime under the Code is of an incentive mechanism form. While this regime makes provision for the sharing with users of pipelines of returns well above the forecast level there remains a significant potential for Service Providers to realise returns well above the regulatory rate.

As Service Providers seek to implement incentive mechanisms in their proposed Access Arrangements they have the opportunity to present a case for retaining a greater share of above-forecast returns that may arise from their particular circumstances. The existence of a flexible incentive mechanism under the Code therefore clearly questions the need for any truncation premium.

Given all of the above, the Commission may wish to give further consideration on the need or appropriateness of recommending the introduction of a truncation premium.

- ***whether a regulator should have the power to examine the costs of an asset management business (wholly owned by a service provider) as part of a service provider's access arrangement review (chapter 10)***

  The Authority does not believe the Regulator can properly conduct the assessment of compliance required under the Code in the absence of adequate information on such contract arrangements with associate service management businesses, and this includes substantiation that only efficient costs of that business are being represented in the charges flowing through to the Service Provider entity. This requirement may have to be reinforced by providing powers to the Regulator to a) require substantiation from the Service Provider and b) inquire, if necessary, into the cost-base of the associated entity to determine whether costs for the services delivered by that associate are reflective of efficient costs including a rate of return justified by the commercial risk in providing that service.

- ***on alternative mechanisms to address the potential for transfer pricing between a service provider and its wholly owned asset management business (chapter 10).***

  The Authority has no alternatives to offer to that discussed above.

- ***whether an asset management business should be required to comply with the ring fencing obligations under ss4.1(a), (b), (g) and (h) of the Gas Code. (chapter 10).***

  The Authority sees no substantial distinction between an associated entity providing a management service as an integral component to the conduct of the business of the Service Provider that is regulated, and the Service Provider itself as far as a capacity to discriminate so as to impact on competition in upstream and/or downstream markets. Accordingly, organizational structures such as asset management companies should be demonstrated by the respective owners to have no potential for discrimination or transfer pricing that would impact on efficient costs, or they should be subject to the equivalent obligations to those of the Service Provider, with the Regulator having the power to grant such exemptions as the case may permit.

ATTACHMENT A

REVIEW OF RATE OF RETURN METHODOLOGIES AND PRACTICES

INSTITUTE FOR RESEARCH IN INTERNATIONAL COMPETITIVENESS
SEPT 2003

R E P O R T

Review of Rate of Return Methodologies and Practices

FINAL REPORT

Review of Rate of Return Methodologies and Practices

FINAL REPORT

by

The Institute for Research into International Competitiveness (IRIC)

Curtin Business School, Curtin University of Technology

Peter Kenyon
Nick Wills-Johnson
Lakshman Alles

for

The Office of Gas Access Regulation

September 2003

Prof Peter Kenyon
Director
Institute for Research into International Competitiveness (IRIC)
Curtin Business School
Curtin University of Technology
Bentley Campus
GPO Box U1987

Perth WA 6845

Tel: 08 9266 3041

Fax: 08 9266 2872

Email: kenyonp@cbs.curtin.edu.au

Web address: http://www.cbs.curtin.edu.au/business/research/iric

Contents

P02001--004.3--NWJ

1 INTRODUCTION

This report presents a review by the Institute for Research into International Competitiveness (**IRIC**), in association with Associate Professor Lakshman Alles of the Curtin Business School, of the methodologies and application of asset pricing or rates of return for the Office of Gas Access Regulation (**O*ff*GAR**). The review also benefited from input from a working group set up to assist in the production of this report comprising staff from O*ff*GAR, the Office of the Rail Access Regulator and Economics Consulting Services.

The aim of the report is to consider evolving best practice in the determination of allowed rates of return in utility regulation to assist further discussion and public consultation. The review draws from both the theoretical literature and regulatory practice around Australia and in other parts of the world. A special focus of the review has been on the treatment of diversifiable and non-diversifiable risk.

The report seeks to address the following issues:

- Review the Capital Asset Pricing Model (**CAPM**) and give consideration to other relevant approaches.
- Review the application of the CAPM methodology in Western Australia (**WA**).
- Review and analyse the rate of return decisions by the WA Gas Access Regulator.
- Review and analyse the rate of return decisions by regulators in other jurisdictions including some relevant regulators overseas.

The report also seeks to address the following issues:

- Whether the CAPM model is the most appropriate basis for determining the rate of return for regulated gas pipelines in WA, considering regulatory practice in Australia and relevant overseas countries.
- Whether the application of the CAPM model in WA has been consistent with that by other regulators.
- Whether the CAPM parameter values selected by the Western Australian Regulator are appropriate taking into consideration WA's specific circumstances.
- Give consideration to parameter values or ranges of values that would be appropriate for regulated pipelines in WA.
- Whether regulatory rates of return in Australia and WA are sufficient to encourage investment in pipelines, citing relevant evidence where appropriate.

1.1 BACKGROUND TO THE REPORT

IRIC has been asked by the Office of Gas Access Regulation (***Off*GAR**) to consider rate of return issues as they relate to the setting of reference tariffs under the *National Third Party Access Code for Natural Gas Pipeline Systems* (**the Code**). Prior to considering these issues in detail, however, it is useful to explore some background, both in terms of the requirements placed on the Western Australian Independent Gas Pipelines Access Regulator (**the Regulator**) by legislation and the reasons underlying the commissioning of this report.

Public policy on access to gas pipelines in WA is governed by the *Gas Pipelines Access (WA) Act 1998,* which gives legal effect to the Code. By law, the Regulator is guided by the requirements of the Code in assessing and approving access arrangements proposed by pipeline service providers for gas pipelines covered by the Code.

The Code was developed to provide rights of access to gas pipeline systems on conditions that are fair and reasonable to both pipeline owners and users.

The objective of the Code is to establish a framework for third party access to gas pipelines that:

- facilitates the development and operation of a national market for natural gas; and
- prevents abuse of monopoly power; and
- promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders; and
- provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users; and
- provides for resolution of disputes.

Under the Code, the Regulator is asked to approve "reference tariffs" for a defined standard service referred to as a "reference service". As explained in section 8.3 of the Code, the manner in which a Reference Tariff may vary within an Access Arrangement Period through the implementation of a Reference Tariff Policy is within the discretion of the Service Provider.

The estimation of some of the elements that are needed in determining reference tariffs, such as operating costs, may be relatively straightforward, but the derivation of an asset value and an appropriate rate of return to the owners of, or investors in a pipeline tend to be far more challenging.

The Code provides three methods for calculating total revenue, each of which includes a rate of return on the value of the assets that form the pipeline:

8.4 The Total Revenue (a portion of which will be recovered from sales of Reference Services) should be calculated according to one of the following methodologies:

Cost of Service: The Total Revenue is equal to the cost of providing all Services (some of which may be the forecast of such costs), and with this cost to be calculated on the basis of:

(a) a return (***Rate of Return***) on the value of the capital assets that form the Covered Pipeline (***Capital Base***);

(b) depreciation of the Capital Base (***Depreciation***); and

(c) the operating, maintenance and other non-capital costs incurred in providing all Services provided by the Covered Pipeline (***Non-Capital Costs*****).**

IRR: The Total Revenue will provide a forecast Internal Rate of Return (IRR) for the Covered Pipeline that is consistent with the principles in sections 8.30 and 8.31. The IRR should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period.

The initial value of the Covered Pipeline in the IRR calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed residual value of the Covered Pipeline at the end of the Access Arrangement Period (***Residual Value***) should be calculated consistently with the principles in this section 8.

NPV: The Total Revenue will provide a forecast Net Present Value (NPV) for the Covered Pipeline equal to zero. The NPV should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period, and using a discount rate that would provide the Service Provider with a return consistent with the principles in sections 8.30 and 8.31.

The initial value of the Covered Pipeline in the NPV calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed Residual Value at the end of the Access Arrangement Period should be calculated consistently with the principles in this section 8.

The methodology used to calculate the Cost of Service, an IRR or NPV should be in accordance with generally accepted industry practice.

However, the methodology used to calculate the Cost of Service, an IRR or NPV may also allow the Service Provider to retain some or all of the benefits arising from efficiency gains under an Incentive Mechanism. The amount of the benefit will be determined by the Relevant Regulator in the range of between 100% and 0% of the total efficiency gains achieved.

The principles for calculating the rate of return are set out in sections 8.30 and 8.31 of the Code as follows:

8.30 The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).

8.31 By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

Under the Code, service providers as investors are to receive a rate of return that is "commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service."[1] The issue of investor returns is discussed further in Chapter Two.

Since the rate of return is to be set commensurate with prevailing conditions in the market for funds, the returns from similar risk investments become the benchmark or, in economic terms, represent the opportunity cost of alternate investments foregone. The cost of capital, for the purposes of economic regulation (or economic cost of capital), includes such opportunity costs. This may differ from the definition of the cost of capital used by accountants, for example.

The Code also requires that the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. In the long run, it can be shown that in an open and competitive marketplace, only firms capable of operating at "best practice" levels will survive. Less efficient firms will sell out or leave the industry.

In determining a rate of return, regulators have the delicate task of striking a balance between the return to investors in regulated pipelines, investors in upstream and downstream industries and final consumers.

If the return on investing in gas pipelines is less than the economic cost of capital, investors in companies which own gas pipelines will be inadequately compensated for the risks that they bear and pipeline operators will not be able to attract sufficient capital from financial markets. This may impair the future financial viability of investment in gas pipelines, and damage the ability not only to sustain operations, but also to carry out future development activities. In a capital-intensive industry such as the gas pipeline industry, the inability to attract sufficient capital would be likely to result in lower levels of pipeline expansion and extension than is economically desirable and lead to sub-optimal levels of economic development and growth.

If, on the other hand, the rate of return on pipeline assets is greater than the economic cost of capital, the consequences can be equally adverse. A rate of return above the opportunity cost of capital will be likely to result in users of the pipeline being overcharged, resulting in lower levels of investment in upstream and downstream industries than is desirable for the economy as a whole and lower consumer welfare.

In a competitive market, firms earn for their investors a rate of return that is equal to the opportunity cost of the investors' capital (or its economic cost). In this way the interests of investors and consumers are balanced such that the community at large obtains the most economic value from the resources utilised in that market.

---

1 Section 8.30 of the Code.

It is also important to be aware that there is a difference between expected rates of return and those actually achieved. Obviously, investors always hope to earn returns that are better than the (risk adjusted) market average when investing; nobody invests intent upon losing. However, by definition, not all firms can perform above the market average. By requiring that the rate of return should be commensurate with prevailing conditions in the market and the risk involved in delivering the reference service, the Code focuses on rates of return actually achieved in the market given the risks involved and not the expectations of investors, which may be greater.

Another important point is the context of the rate of return determined under the Code. Unlike some regulatory regimes in Canada and the US, the Code does not set rates of return for regulated gas pipelines. The rate of return under the Code only establishes a notional total revenue as the basis for determining the reference tariff.[2] The Code does not preclude an efficient pipeline service provider from achieving a return on investment that is higher than the rate of return used in determining a reference tariff.

1.2 REPORT STRUCTURE

The structure of the report is as follows:

- **Chapter 2:** Reviews the latest developments in the theories and practices of asset pricing, focussing both on different methodologies, and on the theoretical backing for the means of determining the various elements of the most commonly used methodology, the CAPM.
- **Chapter 3:** Examines a range of issues that arise when the CAPM is applied in practice. In particular, Chapter Three focuses on the determination of differences between systematic (non-diversifiable) and non-systematic (diversifiable) risk.
- **Chapter 4:** Examines rates of return attained in various industries around Australia and some other parts of the world and compares these with rates of return under the Western Australian regulatory framework.
- **Chapter 5:** Provides a brief conclusion.
- **Attachment 1:** Comments on commonly proposed risks and their systematic or non-systematic nature.
- **Bibliography**

2 The process by which this takes place is well described in almost all Draft and Final Decisions issued by gas pipeline regulators around Australia. For an example, see the Regulator's Final decision for the Dampier to Bunbury Natural Gas Pipeline at http://www.offgar.wa.gov.au/main.cfm

2 THE THEORIES AND PRACTICES OF ASSET PRICING

2.1 THE COST OF CAPITAL

The cost of capital refers to the ‘price’ a firm or entrepreneur must offer to the market in order to attract investors to its operations, rather than to those of its rivals. To do this, the firm or entrepreneur must offer a price just better than all of its rivals. Such a price would, of course, be reflective of relative risks; a more risky investment opportunity would have to offer a lower price (or greater rate of return) than a less risky investment, or it would not attract any funds from investors. This, simplistically, is the genesis of the formal economic concept of the opportunity cost of capital, or the economic cost of capital, which is the relevant factor for use in financial and regulatory analysis, as it captures all of the alternate uses of the capital being put towards an investment being considered.

Cost of capital is a forward-looking concept; investors invest for the future, not the past. In theory, the opportunity cost of capital would be calculated by examining all investors’ expectations about the relative risks and revenue streams of all available investments. In practice, since investors’ expectations are not observable to third parties, it is necessary to estimate forward-looking expectations by examining historical market data. This method introduces some potential for error, but errors are limited by the extent to which the efficient market hypothesis (discussed further below) is true, and represents the best option in light of available alternatives.

2.2 MODELS FOR ESTIMATING THE COST OF CAPITAL

The issue central to the purpose of measuring the cost of capital is the determination of the rate of return for a prospective investment. Any investment will involve risk. A model or methodology for estimating the cost of capital therefore needs to address two issues. One is the meaning of ‘risk’ and how it should be conceptualised and measured, and the other is the specification of the relationship between risk and returns. A number of alternative theories and related models have been proposed. These models are collectively referred to as Asset Pricing Models. All asset pricing models are based on the fundamental premise that investors in capital markets should be rewarded for carrying investment risks. For investors to be willing to carry higher risk investments, they must, on average, be compensated with a higher level of return.

2.2.1 Concept of Risk in Asset Pricing Theory

Risk is conceived as the total variability of the rate of return of a specific investment, which is measured by the standard deviation or variance of returns. In fact, different risks affect a stock in different (and perhaps opposing) ways in a given situation, and hence may offset one another. For example, consider the risk of a hot dry summer; for an ice-cream manufacturer, the risk represents a positive outcome, whilst for an umbrella manufacturer, the outcome is negative. The tendency for risks to affect a stock in different directions leads to the consideration of the net risk position of an investor, commonly termed the 'relevant risk'.

Portfolio Theory, which encapsulates the asset pricing models discussed below, seeks to explain what 'relevant risk' is in terms of the types of risks investors expect to be compensated for in the stock market, or indeed in other markets in which they invest.[3] It was first propounded by Markowitz (1952), and has since found almost universal acceptance amongst both academic and industry analysts. Under Portfolio Theory, investors in markets will design their investments as a diversified portfolio, rather than investing in a single asset or in a small collection of assets. This is because the more diversified a portfolio of investments, the greater the likelihood that risks associated with individual assets within that portfolio will cancel each other out, and hence be diversified away.[4] Such risks are known as 'firm-specific', 'diversifiable' or 'non-systematic' risks.

Not all risks, however, can be diversified away in this manner. Risk factors which are pervasive (like, for example, the risk of global economic downturn), and which cannot be diversified away by purchasing other assets or instruments are referred to as 'non-diversifiable' or 'systematic' risks. Simplistically, systematic risks are emblematic of information shortfalls and asymmetries in the market place. Asset pricing theories argue that the market behaves in a manner to compensate investors only for their exposure to systematic risk, which is unavoidable, and not for bearing risks which can be diversified away by holding a broader portfolio of investments. These then, are the 'relevant risks'.

Importantly, systematic risks are not immutable, but rather, change over time; just because a risk was considered systematic some decades ago, does not mean it will be considered so today. Indeed, from a certain perspective, the growth of new financial instruments can be considered as a response by the

---

[3] For example, land, commodities, insurance and even education (or investment in human, rather than physical capital) are all markets in which investors invest. The stock market is commonly used as a proxy for all potential investments, but that does not mean that it encapsulates all possible markets or investments, which is a common misunderstanding.

[4] In the above example, to address the risks associated with summer weather, an investor might buy stocks in both the ice cream manufacturer and the umbrella maker.

markets to provide new opportunities for diversification for risk averse investors, particularly as information technology advances and globalisation of markets reduce the informational asymmetries which underpin systematic risk. Schiller (2003) provides a useful survey of recent developments and future directions in this regard.

Australia is a small open economy, whose capital markets are well integrated with global markets. Investors in Australian companies and in foreign companies operating in Australia have access to global capital markets and investment opportunities world-wide, as well as the opportunity to evaluate investment opportunities in terms of global market standards. This is an important consideration in determining the relevant risks and appropriate rates of return in the Australian pipeline industry.

In considering risk and its compensation, a key issue that must be considered is the question of who it is that invests in the gas industry (or indeed in any industry). The investors in the gas industry are the shareholders of the firms in whose names pipelines are operated. It is their capital that is at risk when a pipeline is unsuccessful, and it is they who are the residual claimants to any returns when a pipeline is successful. The firms, and their relevant managers, are employed by the shareholders to manage the assets that the shareholders have purchased through their ownership of shares. The better the firm's record at earning good rates of return for shareholders, the more likely that shareholders will wish to buy assets managed by that firm.

The economic theory underpinning the above simplistic description is known as Principle-Agent Theory; shareholders are the 'principals', with capital available to be used to purchase assets, and firms are the collection of 'agents' that shareholders employ to ensure that any assets purchased are managed effectively and deliver rates of return commensurate with the risks involved in the industry. In a competitive market, the incentives of the agents and the principal are aligned, resulting in maximal earnings for each; principals via an increase in the residual claim they have on returns made when the assets are utilised, and agents through an increase in the management fees (or salaries) they are able to command, which is directly correlated with their skills in management.

However, if a market is not competitive, agents may be able to earn high returns for their principals, not through superior skills, but through the market power inherent in the monopolistic assets which the firm manages, which allows the firm to charge higher prices than would be possible in a competitive market, thus earning 'supernormal' profits. This is a positive outcome for the relevant group of investors, but not for the economy as a whole. Since the most efficient use of resources within an economy depends crucially on the most skilled managers of each resource being employed in managing that resource and not on the supplanting of such skills with an ability to abuse market power, the result of high earnings through the abuse of market power in one industry is welfare losses for the community at large (including investors in other industries). In some instances, the market is self-correcting; supernormal profits attract entry to an industry and the resulting competition lowers prices. However, this does not always occur and where it does not, regulators may play a role. In essence, the role of a regulator is to ensure that returns made by investors who purchase an asset by virtue of their share ownership in a firm, earn only those returns which a competitive market would provide to the most skilful managers of that particular asset in the face of numerous competitors, and not supernormal profits associated with a lack of competition and ability to abuse a position of market power.

2.2.2 The Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) is the asset pricing model most widely used by practitioners in the finance industry. The CAPM views the portfolio of all risky assets, referred to as the 'market portfolio' as the appropriate benchmark for measuring systematic risk. The measure of systematic risk of a company is measured by the company's beta. Beta is a standardised measure of the covariance of the company's stock returns with the returns of the market portfolio. The beta therefore measures the *relative* variation of a stock's returns to the variation of the market portfolio of returns.

$$\beta_i = \frac{COV(R_i, R_m)}{VAR(R_m)}$$

where: R_i is the rate of return of any asset i;

R_m is the return on the market portfolio;

Cov(.) is the covariance; and

Var(.) is the variance.

The 'market portfolio' however, is a theoretical construct. In the real world, the market portfolio of risky assets is neither measurable nor identifiable. When the CAPM is applied in the real world, practitioners must employ a suitable proxy. The proxy most widely used is the broad-based national stock market index. The beta of a firm that is computed for purposes of applying the CAPM is the beta relative to the stock market index, and not the true beta. The use of the national stock market index in this way is the accepted standard in the application of the CAPM. However, it is important to recognise that it is a proxy, and that markets other than the stock market exist. Lettau & Ludvigson (2001) present an analysis of the CAPM in wider markets. Note also the way in which beta is calculated in financial markets; by reference to returns, not individual risks, and compare this to the discussion in Chapter Three concerning how the Regulator must determine beta.

The CAPM specifies the relationship between the expected rate of return of any asset $E(R_i)$ and its beta risk, β_i as shown by the equation:

$$E(R_i) = R_f + \beta_i [E(R_m) - R_f] \qquad (1)$$

Where: R_f is the risk-free rate;

R_m is the expected return on the market portfolio; and

E(.) denotes the expectations operator.

The CAPM is a forward-looking model based on a maximisation problem whereby investors chose a portfolio of assets, which trades off expected return against risk. Expected returns are determined in relation to beta risks. But the application of the CAPM by both regulators and financial analysts is based necessarily on the historical record of realised (or ex-poste) returns, rather than expectations of future (or ex-ante) returns. The reason for doing so is that these data are the only ones available (expectations being inherently unobservable). However, under the efficient markets hypothesis, expectations of individual investors should (on average) be correct, and hence historical price data will accurately reflect expectations. The degree to which the efficient markets hypothesis is correct is a matter of some conjecture in the literature (see Section 2.2.3.4), particularly when markets experience shocks not anticipated by investors, but the use of historical information in appropriate modelling scenarios remains the best approach generally available.

2.2.3 Alternative Methodologies for Estimating the Cost of Capital

Several alternative approaches to the Capital Asset Pricing Model have been suggested for estimating the cost of capital. These are summarised briefly below.

2.2.3.1 The Gordon Growth Model

The Gordon Growth model is derived from the basic financial paradigm, which states that the price or value of a share of stock is the discounted value of the future cash flows accruing to it, namely the stream of future dividends. If the assumption can be made that the stream of future dividends paid out by the firm has a constant rate of growth (g), then the price or value of the share today (P), can be shown to be as follows:

$$P_i = \frac{D_i}{k_i - g_i} \qquad \text{for } g < k$$

Where: D is the expected dividend next period; and

k is the discount rate applied to future cash flows.

The discount rate k is also the rate of return on the share expected by investors. By rearranging the model, the expected rate of return can be calculated as follows:

$$k_i = \frac{D_i}{P_i} + g_i$$

The model's attraction is its simplicity. But the validity of the model in a regulatory rate of return situation would depend on the confidence with which a constant growth rate for all future dividends can be assumed for the firm in question. If this assumption cannot be justified, the Gordon Growth Model will not be an appropriate model to use in a regulatory rate-setting situation. But assuming the constant dividend growth assumption is acceptable, the reliability of the cost of capital estimate derived from the model will still critically depend on the reliability of the value estimated for the dividend growth rate. An inappropriate or unrealistic model input estimate will invariably result in an unrealistic model output.

2.2.3.2 Multi-Stage Dividend Growth Models

The limitation of the Gordon Growth Model is that it cannot accommodate situations where the dividend growth rate of the firm may be expected to change in the future. To accommodate such situations, multi-stage dividend growth models are employed. A two-stage dividend growth model can accommodate one expected change in the growth rate. Analysts usually make one forecast for the near term growth rate and a second value for the longer term growth of dividends. Likewise, a three-stage growth model can accommodate two forecasted changes in the future growth rate. Three forecasts will be made one each for the short term, medium term and the long term.

In multi-stage dividend growth models a closed form solution for the expected rate of return may not be available, and the solution to the model equation may have to be determined by iterative procedures. Once again, the critical factor in these models is the reliability of the values forecast for the future dividend growth rates.

2.2.3.3 The Arbitrage Pricing Model

The Arbitrage Pricing Theory (**APT**), originally proposed by Ross (1976), is accepted among academics as a more intuitively appealing model than the CAPM because the APT does not require unrealistic assumptions such as the existence of a hypothetical 'market portfolio' as required by the CAPM. Also the APT does not require the market portfolio to be the sole benchmark 'risk factor' that drives the systematic risk of all individual stocks. The APT is a model of asset pricing equilibrium in capital markets predicated simply on the assumption that arbitrage profit opportunities in capital markets will be quickly exploited by investors.

The APT model acknowledges that the expected rate of return of an individual stock may be influenced by one or several systematic risk factors, if they exert a pervasive influence on the expected returns of many individual stocks. Likely candidates for such risk factors are unexpected changes in interest rates, unexpected changes in inflation, unexpected changes in Gross Domestic Product (**GDP**), global shocks to energy prices etc. More generally, "macroeconomic factors" are likely candidates for systematic risk factors. The magnitude of the influence that each risk factor will have on the rate of return of an individual stock will depend on the particular stock's sensitivity or beta, to each risk factor. A model of the APT with k number of influential risk factors is represented as follows:

$$E(R_i) = R_f + a_1\beta_1 + a_2\beta_2 + a_3\beta_3 + \ldots + a_k\beta_k \qquad (2)$$

Where: $E(R_i)$ is the expected return on asset or security i,

$a_1 \ldots a_k$ are the market prices of risk relating to each risk factor, and

$\beta_1 \ldots \beta_k$ are the sensitivities of security i to each risk factor.

Despite the acknowledged elegance of the model, there are a number of issues that must be addressed prior to its use in practical application. The first issue is that the APT theory itself does not identify or specify the risk factors that should be included in the model. The risk factors need to be selected by the analyst. Typically the analyst would base this decision on the analysis of past evidence relating to the observed impact of identifiable risk factors on the firm or firms investigated. The second limitation of the APT is that the model does not specify the number of risk factors to be included in the model. The researcher needs to decide how many risk factors are influential. Such open endedness in the theory has led researchers to propose a wide variety of model specifications, depending on the country of application, the time period analysed and the nature of the firms used in the analysis. As a result, there is no uniformity or universal acceptance of a single APT model specification among practitioners.

The lack of a clearly prescribed model specification has so far discouraged regulators from using the APT in rate regulation and cost of capital computation. Nevertheless, the APT is a significant advance in explaining asset prices, and there is scope for its use in clarifying the nature of systematic risk.

Empirical studies examining the suitability of the APT remain somewhat inconclusive. For example, Bubnys (1990) testing the superiority of the APT in comparison to the CAPM, in terms of the models' ability to forecast the rates of return for a sample of U.S. utility companies, concludes that neither model is clearly superior.

2.2.3.4 The Fama-French Three Factor Model

In a series of papers, Fama and French (1992, 1993, 1995, 1996) demonstrate that the CAPM-related beta factor is a poor predictor of the relative variation of a stock's returns to that of the market portfolio of returns. Fama and French demonstrate that stock characteristics such as the book-to-market ratio (B/M ratio) and the firm's market value or size not only explain the cross sectional variation of returns much better, but that in a multivariate setting, they subsume the explanatory power of accepted variables such as the CAPM beta. Fama and French (1993) demonstrate that constructed risk factors related to size, denoted as SMB, and the B/M ratio, denoted as HML, have the ability to explain the cross sectional variation in stock returns. Since then, the SMB risk factor and the HML risk factor together with the market factor, have figured prominently in a multi-factor asset pricing model, known as the Fama-French three factor model. This is specified as follows:

$$R_i - R_f = a_i + b_i (R_m - R_f) + s_i \text{ SMB} + h_i \text{ HML} + e_i$$

Where SMB (Small Minus Big) mimics the risk factor in returns related to size, and is calculated as the difference between the returns on small and big stock portfolios with about the same weighted average book-to-market equity, and HML (High Minus Low) mimics the risk factor in returns related to book-to-market equity, and is calculated as the difference between the returns on high and low book-to-market equity portfolios with about the same weighted average firm size.

The Fama-French model is of more recent vintage compared to other asset pricing models, such as the CAPM and APT, but it has made a strong impact on the finance community. However, despite the model's demonstrated predictive ability, it has still not been fully accepted as an asset pricing model, largely because the role of the central risk factors in the model, the SMB and the HML, are not clearly understood or acknowledged. While the model's validity is still being debated in academic circles, its acceptance and use in a regulatory environment as an alternative to the CAPM may still be quite some time away.

2.3 METHODOLOGY FOR ESTIMATING THE CAPM PARAMETERS

All the models suggested as alternatives to the CAPM are still being debated in academic circles and their practical application to regulatory rate setting remains uncertain. In the face of no clearly superior approach, the CAPM continues to be used as the principal model for cost of capital computation.[5]

[5] In the US and New Zealand telecommunications industries, the Efficient Component (or Baumol-Willig) Pricing Rule is used, and some UK water companies have also indicated they will use this method in forthcoming access arrangements. However, this rule has limited applicability in the WA gas pipeline industry, as it usually requires the natural monopoly infrastructure owner to have interests in upstream and downstream industries. Some US regulators in other industries (including gas pipelines) use the dividend growth model. However, this relies on the regulated firms having traded stocks, which is not the case in WA.

These include Australia, the UK, Argentina, Austria, Ireland, Norway, Spain and Sweden. Moreover, it is widely used in the private sector. Meier & Jagannathan (2002) have suggested that this may be due to the fact that it is so widely taught at graduate MBA courses in US universities. A less prosaic reason may be that, despite its shortcomings, it has the least onerous information requirements and is, of the methods available, the least subject to judgement.

In utilising the CAPM framework, regulators do not simply use just the CAPM equation discussed in Section 2.2.2. Rather, because firms can source funds from either investors (equity) or lenders (debt), a Weighted Average Cost of Capital (**WACC**) calculation is appropriate. The calculation of the WACC is described below.

When a company that owns and operates a pipeline is financed by both equity and debt, the firm needs to earn an overall rate of return on its assets that is sufficient to meet the expected or required return of its equity holders and interest payments to its debt holders. This return is a weighted average of the after-tax cost of equity and the after-tax cost of debt, weighted by the market values of equity and debt respectively. The WACC formula derived on this basis is shown below. This form of the WACC formula is used by firms and regulators in countries where the classical tax system prevails.[6] The formula is based on the assumption that the firm has a constant target debt-to-equity ratio and that the project cash flows are constant in perpetuity.

$$\text{WACC} = \left[\frac{E}{V}\right]R_e + \left[\frac{D}{V}\right]R_d$$

Where: E is the market value of the company's equity;

D is the market value of the company's debt;

V = E + D;

R_e is the share holders required rate of return, equal to the cost of equity; and

R_d is debt holders required rate of return, equal to the cost of debt.

This section examines the various different parameters that are utilised in WACC calculations by regulators, from the perspective of both the relevant theoretical paradigms and the practice of regulators.

6 Such as the US. This is distinct from the imputation tax system, which operates in Australia.

2.3.1 The Risk-Free Rate

One of the parameters to be estimated in the CAPM formula is the risk-free rate. The financial asset nearest to being risk-free in Australia is the Commonwealth Government bond. The risk-free rate can therefore be approximated as the yield to maturity on this security in nominal terms. This rate would include the premium for expected inflation over the maturity period. When the term structure of interest rates is not flat, government securities with different maturities will provide different yields. Therefore the maturity period of the asset selected must be close to the period over which the cost of capital is to be computed. If an investment is of a long-term nature, a long maturity bond such as the ten-year bond is more appropriate. Selecting a bond with high market liquidity is also important. If not, the yield would incorporate a liquidity risk premium, and distort the risk-free status assumed of the bond.

Almost all jurisdictions use a government bond that is relevant in the circumstances, generally a ten-year bond.[7] In the US and Australia, these are Treasury Bonds, in Canada they are Government of Canada Bonds, and in the UK, they are Gilts. A recent decision by the Queensland Competition Authority (**QCA**) (2001, p211) indicates that Australian regulators used 10-year Treasury Bonds in 16 of 18 recent decisions. It is important to note that government bonds are a proxy for the risk-free rate, and are not automatically risk-free. Green & Rodriguez-Pardina (1999, p95) discuss how Argentinean regulators (working within a regulatory framework broadly similar to that in the Australian gas industry) use US Government Treasury Bonds as the risk-free rate, and add to this a country risk premium associated with investing in Argentina. As subsequent history has shown, the regulators were correct in doing so, as Argentinean Government debt was indeed not risk-free.

Some countries issue 25-year bonds, which are closer in maturity to the economic life of a gas pipeline. However, these are seldom used, due to concerns that their lack of liquidity might bias their use as a proxy of the risk-free rate.

In the efficient markets hypothesis theory, the spot rate for a bond reflects all of the available market information associated with future risk-free rates, but few regulators have been willing to adopt such an approach. In a recent decision, the QCA (2001, p211) report that most Australian regulators have used some form of moving average, ranging from 20 days (55 percent of cases) to 12 months (11 percent of cases). Regulators do this to smooth day-to-day fluctuations, and to refect the fact that information asymmetries in the

[7] In ACCC (2001a) the ACCC has utilised 5-year bonds, and some suggest this is appropriate (e.g., see Lally, 2002), as these more accurately reflect the duration of interest rate swaps, or that longer term instruments are unsuitable proxies when prices adjust annually. Although the debate is ongoing, it has yet to affect many regulatory decisions.

market mean that spot prices might not reflect all information. However, a danger exists in that, if the length of time used increases, so too does the potential that biased information will be included. In many cases regulators develop a range for the risk-free rate based on available data that is then smoothed and make an informed judgement on where within the range the choice should be made. While this approach by regulators introduces some element of arbitrary decision-making, an open and transparent regulatory process allows parties in a regulatory decision to more easily determine the source of any issues, and negotiate their amelioration.

2.3.2 The Expected Market Risk Premium

A key input to the CAPM is the economy or market-wide expected risk premium. The proxy most often used for this is the expected return on a broad-based basket of stocks such as those used to derive the ASX 500 less the risk-free rate. But since the expected return is not directly observable, practitioners often use the average return on the stock market index over a historical time span as the best estimate of its future expected value. This raises the danger that future market conditions and current expectations will be different to the conditions that prevailed during the historical sample period.

Another difficulty arises in selecting an appropriate sample period for the purpose of calculating averages. A short, recent sample period may be a good indicator, but can be subject to high sample variation, as the stock market index return is highly variable over time. Taking an average over a longer time period averages out the short-term variations, but can give rise to biased results influenced by past trends. The issue is similar to that for bonds, discussed above.

Another issue relates to whether the arithmetic mean or the geometric mean of the annual returns should be used. This issue is discussed in Fuller and Hickman (1991), who conclude that the arithmetic mean is the preferred choice.

Although, in theory, the market risk premium should reflect all available investments (for example, in commodities, insurance and hedging instruments and human as well as physical capital), in practice, almost all regulators and other financial professionals utilise some form of average of stock market returns to estimate the market risk premium. In general, the market risk premium is estimated based on historical trends. However, estimates could also be based on surveys of the expectations of market participants or other modelling data based on accounting or consumption data. The UK Office of Gas and Electricity Markets (**OFGEM**) utilises estimates based on the expectations of British Financial Markets and institutional investors to assist it in estimating the market risk premium.

In Australia, Davis (1998) has suggested a downward trend in the market risk premium. However, most regulators still utilise a figure of six percent, although the Australian Competition and Consumer Commission (**ACCC**), in a recent decision (ACCC 2001a, p40), appears to have foreshadowed future reductions in its estimate of the market risk premium.

2.3.3 The Estimation of Betas

To apply the CAPM for cost of capital computation, the beta estimate required is a forward-looking beta. Here again, beta is not directly observable and must be estimated. The general approach is to estimate a forward-looking beta on the basis of historical estimates using Ordinary Least Squares regression analysis.

To estimate the beta of a stock i using the market model, the required model inputs are the time series of rates of returns of the stock i, over a historical sample period, and the time series of returns of the stock market index calculated over the same period. The market model is given as follows.

$$\tilde{R}_{it} = a_i + \beta_i \tilde{R}_{mt} + \tilde{e}_{it}$$

Where: $\tilde{R}_{it}$ is the returns of stock i in period t;

$\tilde{R}_{mt}$ is the returns of the market index in period t;

a_i is the intercept, being the average return on asset i when the market return is zero; and

β_i is the slope of the regression line.

$\tilde{e}_{it}$ is an error term.

To estimate the beta for a firm using this approach, traded market prices for the stock need to be available. If the company is not listed on the stock exchange, or if the firm is a subsidiary company of a larger corporate conglomerate, market prices for the stock will not be available. In such circumstances market betas cannot be calculated, and another approach is necessary. This is precisely the problem faced by Australian regulators, and is discussed further in Chapter Three.

The accounting beta approach is one alternative in the absence of market data for the calculation of market betas. In this case accounting data on return on assets are used as a substitute for market data. Regression analysis is used, where the return on assets (**ROA**) for the utility is regressed on the average ROA of the market index such as the ASX 500 or a group of publicly-traded utility companies. The slope of the regression line indicates the beta value that may be used in the CAPM equation.

Critics of this method express the view that accounting betas may not reflect current information, because financial statements are based on historical data. This situation may, however, have improved since 1984. The international

Financial Accounting Standard (**SFAS**) 33, (adopted in Australia's "Financial Reporting and Changing Prices") requires constant dollar and current cost accounting restatements of historical cost financial statements. After 1984, the reporting requirements of SFAS 33 no longer includes constant dollar restatements. The improvement in the quality of earnings numbers resulting from this change in disclosures of SFAS 33 may improve the quality of accounting betas. However, this does not address the more fundamental criticism that accounting betas are calculated based on data internal to the firm, whilst the theoretical underpinnings of beta as a description of systematic risk lie firmly in exogenous factors. For example, debt ratios are likely to be correlated with exogenous financial market factors which represent systematic risks. However, the use of accounting data to calculate betas introduces the risk that the underlying exogenous variables are less than perfectly correlated with the financial statement data and hence that results calculated using the financial statement data will be incorrect.

Several issues need to be considered when using a beta based on historical data as an estimate of the forward-looking beta. The first issue is that the beta of a firm is dependent on the characteristics of that firm. For example, if the characteristics of a firm over the last five year period on which the beta was estimated are likely to be different to its characteristics in the next five year period, when the cost of capital is to be applied, then the beta should be adjusted to appropriately reflect expected future changes. Rosenberg and Guy (1976) identify a number of characteristics that can influence the beta value for a firm. Among them are the firm's debt to equity ratio, the firm's market capitalisation, and changes in the variance of earnings and cash flows.

The difficulties faced in calculating betas are discussed in more detail in Chapter Three. In light of these difficulties, the common response of regulators around the world has been to take a beta value from the nearest comparable market beta and adapt it to suit the local regulatory environment (proxy beta). Regulators in the UK, for example, are known to have based beta estimates on the market beta for a firm having both regulated and non-regulated assets by adjusting the beta to remove the effect of the non-regulated components. This approach was taken by OFTEL (for British Telecom) and the UK Office of the Rail Regulator (for Railtrack).

In Australia, few infrastructure assets are traded in the market.[8] The response of early regulatory decisions, (ACCC, 1998, p47-8) was to take some average of traded assets from overseas (usually the US and/or UK) and then adapt this

8 In a footnote the ACCC notes that the asset betas for comparable utilities that are traded in the Australian stock market are: AlintaGas, 0.30, APT, 0.38, Envestra, 0.10 and United Energy, 0.53 (ACCC, 2001a, p51). Aside from United Energy, these are all substantially below the asset betas commonly given in Australian regulatory decisions (see for example QCA, 2001 p226), but it should be noted that most of these stocks have only been listed for a short period of time and hence only limited inferences can be drawn from these figures.

to reflect Australian market conditions. Later Australian regulatory decisions have often based decisions on beta on the perceived riskiness of the particular pipeline being regulated compared to those for which betas have been determined in the past in Australia. Tables comparing betas allowed in previous regulatory decisions in Australia are a common feature of Draft and Final Decisions by regulators. We do not believe this to be an ideal approach, as the comparisons made are often subjective, but recognise the limited availability of alternatives.

2.3.4 Cost of Debt and Debt Margins

The cost of debt to the firm is the rate of return required by lenders to extend the loan. Like equity holders, lenders also have an opportunity cost of capital, and will not lend where alternate borrowers with the same risk of default are prepared to pay a higher borrowing rate for the same funds. Firms may raise debt from a variety of sources. Borrowings may include short-term or long-term sources. Debt may also be marketable or non-marketable. The overall cost of debt is a weighted average cost of the various sources of debt.

The debt margin refers to the premium, above the risk-free rate, that a firm must offer in order to secure debt financing.[9] A common approach amongst both Australian and overseas regulators when examining debt margins is to examine (or in some cases estimate) the credit ratings of the parent firm (QCA, 2001, p219). The Regulator can then examine recent debt issues by firms with similar credit ratings, and estimate the premium over the risk-free rate for those corporate bonds. The ACCC (in its Moomba to Adelaide decision), IPART (for AGLGN) and the Queensland Competition Authority (for Queensland Rail) have estimated the debt premium on the basis of the credit rating of companies assessed as facing similar risks. OFTEL and the UK Office of the Rail Regulator have also adopted a similar approach, as has the Netherlands Electricity Regulatory Service (**DTE**).

2.3.5 Capital Structure and Gearing

The capital structure of a firm or gearing refers to the mix of debt and equity sources of funds arranged by the firm. The question of what constitutes an 'optimal' capital structure has been the subject of some debate in the academic literature, with several competing viewpoints being offered. Empirical evidence on capital structure tends to support the idea that firms tend to target

[9] Whether it includes costs associated with obtaining debt financing (such as banking or legal fees) which are accounted for in the cash-flow depends on whether such costs have been included elsewhere, for example in cash-flow. QCA (2001, p222), did not allow a margin for these costs, but in its GasNet decision, the ACCC has allowed a margin in the cost of debt for transaction costs, ACCC (2002c, p91).

a chosen level of gearing. This target may, however, differ from one industry to another, and also may depend on whether the firm is regulated or not.

In considering a capital structure, regulators generally adopt the concept of an "efficient firm" as a standard. For example, Section 8.31 of the Code specifically provides that

> In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice.

A 60 percent gearing ratio is used in 18 recent Australian decisions and is also used in the Netherlands.[10] In its Moomba to Adelaide Draft Decision, the ACCC was challenged to provide validation for its choice of a gearing ratio of 60 percent to which it responded with a report by Standard and Poors, showing that international utilities have gearing ratios averaging between 55 and 65 percent (ACCC, 2001a, p41).

The gearing level of 60 percent used by Australian regulators in gas regulatory decisions appears to be consistent with actual gearing levels of a majority of listed gas utilities. Table 1 shows gearing levels for gas companies listed in Australia, as outlined in the most recent financial statements in the relevant annual reports.

Table 1 Gearing Levels of Australian Listed Gas Companies

Company	Financial Statement Date	Gearing (%)
AlintaGas	30 June 2002	57
Australian Pipeline Trust	30 June 2002	63
Australian Gas Light	30 June 2002	61
Envestra[11]	30 June 2002	94
United Energy	31 December 2001	59

The UK and Ireland adopt a similar approach to that adopted in Australia and the Netherlands, basing the gearing ratio on an "efficient firm" concept and not on the actual ratio applicable to the firm. The UK and Ireland have adopted a value of 50 percent as distinct from that adopted in Australia, which tends to be 60 percent. In the US and Canada, the actual gearing of the firm is more commonly used, however, these countries have a different method of

[10] Australian information from QCA (2001, p223). Netherlands information DTE (2000 p22).

[11] Envestra treats its loan notes as equity in its 2002 Annual Report, which gives the very high gearing ratio shown. If loan notes are not included as equity, gearing falls to 83 percent, which is closer to other firms shown, but still high.

regulation to that used in Australia. Even given this, however, many recent decisions in the UK, USA and Canada show gearing levels of approximately 50 percent (NERA, 2001a, pp15-16).

The range of debt levels used by regulators seems to demonstrate that this issue has not been settled, but most industry analysts seem to accept that a gearing ratio of 50-60 percent is reasonable, and indeed is reasonably similar to actual gearing levels for most Australian listed gas companies.

2.3.6 Inflation

The methodology applied in cost of capital computation needs to account for expected inflation over the assessment period. One method used to estimate inflation is to derive such an estimate from the difference in the yield between indexed and non-indexed government bonds, with a similar maturity. Inflation is generally inferred from the difference between real and nominal rates (from the relevant bonds) via the Fischer Transformation method. All Australian gas access regulators now use this approach.

An alternate approach is to utilise predictions of CPI, which alleviates the issue that trading in bonds may be of insufficient depth to truly reflect inflation expectations. However, as noted by the ACCC (2001a, p39), CPI figures are "inevitably out of date, may be subject to some institutional bias and do not necessarily relate to the access arrangement period under consideration."

2.3.7 Tax Rates and the Treatment of Tax

2.3.7.1 Pre-Tax Real or Post-Tax Nominal?

Tax legislation differs markedly around the world, and hence there is limited value in comparing how tax is treated from jurisdiction to jurisdiction for the purposes of capital asset pricing. For this reason, the comparison in this section is limited to Australian circumstances.

A simple WACC is the weighted average cost of capital sourced from investors and lenders. This WACC represents a nominal rate of return.

The approach often adopted by regulators in Australia has been to gross-up the post-tax nominal WACC to obtain a real pre-tax WACC. This involves incorporating taxation and inflation into the WACC calculation utilising the formulae described at the beginning of Section 2.3. Transformation can occur via a number of approaches (Vanilla, Monkhouse and Officer are three common examples), each of which has its positive and negative aspects.

The ACCC has recently opted to change the method by which it accounts for taxation, and utilises a post-tax nominal WACC.[12] Taxation is thereby explicitly incorporated into cash-flows on an annual basis.[13]

There are a number of arguments in support of each of the alternative approaches. The post-tax nominal approach has recently been adopted by the ACCC, while the pre-tax real WACC approach has been used in most other regulatory decisions around Australia.[14] The pre-tax real framework approximates the effect of tax through the rate of return, while the post-tax nominal approach models tax more explicitly as part of the cash flows.

However, a number of real issues exist in relation to the use of each method. For example, a pre-tax real framework does not ensure the correct rate of return over multiple regulatory periods, whilst the post-tax nominal framework suffers from the 'S-Bend' problem; the fact that customers at different points in time will pay different access charges according to the changing tax position of the entity. This not only raises inter-generational equity issues, but may also alter incentives for customers of regulated pipelines and hence affect efficient resource allocation. The main point is that, current views of the ACCC notwithstanding, neither the pre-tax real nor the post-tax nominal approaches have been clearly shown to be superior.

A further difficulty associated with adopting a pre-tax real approach to calculating the WACC is that it necessitates choosing whether effective or statutory tax rates should be used. There are a number of issues associated with this choice, which are discussed by the ACCC (1998, pp56-9). Essentially, the point is that a Regulator would use effective tax rates to ensure that, at each point in the life of the relevant asset, the applicable tax is used in the calculations. However, it is difficult to accurately estimate effective tax rates without resorting to the modelling of tax in cash flows. Hence, regulators have tended to use the statutory tax rate[15] knowing that to do so favours asset owners on account of accelerated depreciation and other tax concessions provided by Government.

---

[12] In its recent decision, the QCA followed the ACCC, requiring Allgas and Envestra to adopt a post-tax nominal approach. See QCA (2001) pp206-208

[13] It is also possible to add a "tax wedge" to rates of return, which is the approach adopted by some UK regulators.

[14] The ACCC develops these arguments in ACCC (2000b), pp36-41. The ACCC has also released a *Post-Tax Revenue Model* and *Post-Tax Revenue Handbook* (explaining how to use the model). Both are available from http://www.accc.gov.au//gas/fs-gas.htm.

[15] See QCA (2001) p238. All 18 decisions summarised have utilised the statutory rate. The actual values used have changed slightly as the corporate tax system has changed recently. Consequently, some regulators have used the former corporate tax rate of 36 percent, some have used the new rate of 30 percent, and some have used a combination of both. The choice essentially reflects the timing of each decision.

The use of a post-tax nominal WACC with tax modelled in cash flows has, however, drawn criticism from infrastructure owners arguing that by adopting this approach regulators are depriving asset owners of a tax benefit provided by Government to encourage investment.

The alternate view is that market pressure, where a market is competitive, ensures that tax concessions are passed on to consumers resulting in lower prices encouraging increased demand for services, investment and economic development. Where the market is not competitive no such pressure will exist.

The issue for Government therefore is whether regulators should seek to ensure that tax concessions provided to natural monopolies are passed on to consumers in the interests of stimulating increased demand, investment and economic development.

2.3.7.2 Gamma

Australia operates an imputation tax system whereby corporate taxes take the form of a withholding tax or an advance payment of personal tax for resident Australian shareholders of a company.[16] The advance payment is recouped by the shareholder as a franking credit in the personal tax computation. Recoupment of the corporate tax payment is not available to non-resident shareholders. If all the shareholders of a company were Australian residents the entire corporate tax payment would be recoverable as imputation tax credits. In this case, the effective corporate tax rate is zero. On the other hand, if all the shareholders of a company were non-residents, no corporate taxes would be recoverable as imputation tax credits, and these shareholders would effectively bear the full corporate tax rate. Since the shareholders of a typical company are a mixture of residents and non-residents, some proportion gamma (γ) of the tax collected by the company is claimed through franking credits. The effective company tax rate (t_e) will then be some rate within the range of zero and the statutory corporate tax rate. Officer (1994) provides a detailed analysis of this, and assuming the firm has a 100 percent dividend payout ratio, shows the effective tax rate (t_e) to be as follows:

$$t_e = t_c (1 - \gamma)$$

Where: t_c is the statutory corporate tax rate, and

[16] The Australian system differs from that in other counties such as the USA where the classical tax system applies. The CAPM, APT and other asset pricing models have been developed for the classical tax system. In applying the CAPM to the Australian context, some adjustments need to be made to the asset pricing equation to reflect the tax system applicable in Australia. Under the classical tax system, corporate tax is a separate tax incident on the profits of a company. Income of the company accruing to the shareholders is subject to tax at two points: first at the company level as corporate tax, then as personal income tax when the after-tax income is paid out as dividends and received by the shareholders.

γ is a value between zero and one and represents the proportion of the company tax recovered through franking tax credits.

Under an imputation tax system, when the rate of return on an investment in shares is measured, the franking tax credit must be added to the capital gain on the share and the dividends received on the share. This is usually referred to as the 'grossed up' return. Returns measured in this way take account of the corporate tax credit, but do not deal with personal taxes payable by the investor. The returns are therefore measured 'after company tax but before personal tax'.

When the CAPM is used for computing the cost of capital, the rate of return that goes into the model inputs must be calculated on an 'after company tax' basis. To adjust the market return to an after-tax basis, a franking premium tau (τ) is added to the market return. This adjustment reflects the average dividend yield on the shares and the extent of franking credits inherent in those dividends.

$$E(R_i) = R_f + \beta_i \, [E(R_m + \tau) - R_f]$$

A similar adjustment to the rates of returns for the firm and the market index must also be incorporated when estimating the firm's betas.

The WACC formula given at the commencement of Section 2.3 needs to be adjusted to take account of the imputation tax system applicable in Australia. Officer (1994) has developed the following equation for computing the after-tax WACC for Australian firms. The formula assumes the firm has a 100 percent dividend payout ratio.

$$\text{WACC} = \left[\frac{E}{V}\right] R_e \left[\frac{1 - t_c}{1 - (1 - \gamma) t_c}\right] + \left[\frac{D}{V}\right] R_d \, [1 - t_c]$$

If the firm adopts a dividend payout ratio of alpha (α) (a value between zero and one), which is observed in most firms, the WACC formula should be modified as follows:

$$\text{WACC} = \left[\frac{E}{V}\right] R_e \left[\frac{1 - t_c}{1 - (1 - \alpha\gamma) t_c}\right] + \left[\frac{D}{V}\right] R_d \, [1 - t_c]$$

Only Australia and the UK have imputation tax schemes and it is only Australian regulators who give consideration to a gamma figure, which represents the proportion of franking credits that can be used to offset tax payable on other income. In all cases in Australia, regulators have not adjusted for the actual composition of shareholders (domestic or foreign), but have assumed 100 percent Australian ownership. This reflects the view expressed by the ACCC (1999, p82) that "there is no well founded basis for discriminating in favour of one type of investor or another, and such discrimination may lead to different regulatory outcomes emerging purely on the basis of ownership." The ACCC also notes that the inability of foreign investors to take advantage of imputation credits may be offset by other CAPM parameters (ACCC, 2001a, p42).

The value chosen for gamma is generally 0.5.[17] This is based on work by Hathaway and Officer (1995), which suggests that 80 percent of company tax payments are distributed as imputation credits, and that 60 percent of distributed franking credits are redeemed by taxable investors (0.8*0.6=0.48 or approximately 0.5).

2.4 WA'S CAPITAL ASSET PRICING METHODOLOGY

The main features of the methodology used by the Western Australian Gas Pipelines Access Regulator are as follows:

- The risk-free rate is calculated according to a 20-day moving average on a ten year Treasury bond.
- The market risk premium used by the Western Australian Regulator has been six percent, in line with research suggesting that this has represented a reasonable proxy of the market risk premium. However, the maintains a watching brief to ascertain whether this figure should change.
- Beta is calculated on a case-by-case basis based on current market information and comparable previous regulatory decisions.
- Debt margins are calculated according to market information having regard to credit risk.
- Capital structure is calculated in accordance with the requirements of the Code having regard to the gearing level of an efficient firm for the industry.
- Inflation is estimated as the difference between government bond yields and the yield on an indexed Treasury bond.
- A gamma of 0.5 has been used, in line with empirical findings of Hathaway and Officer (1995).
- The statutory tax rate is used for estimating tax liability.
- In decisions to date a real pre-tax framework has been adopted in estimating the WACC. However, a watching brief is being maintained on the ACCC's approach of post-tax nominal WACC.

The above features are broadly in line with the methodologies used by other regulators both in Australia and overseas.

[17] QCA (2001 p234) shows 12 recent decisions with a choice of 0.5, and the remaining 6 choosing a range between 0.3 and 0.5.

3 ASSESSMENT OF FACTORS UNDERLYING RETURNS UNDER CAPM

This chapter examines the various factors which underpin returns in the regulatory use of CAPM. In particular, it assesses a number of reasons put forward by either pipeline operators or in public submissions as reasons for a particular rate of return. A key issue is the nature of risks, and as such, these are discussed first. Other factors are discussed in Section 3.2.

3.1 RISKS APPROPRIATE FOR CONSIDERATION UNDER CAPM

When estimating the WACC, it is apparent that a number of the parameters used are in the nature of market information and are therefore in the public domain. These parameters include the risk-free rate, tax rate and inflation.

A second category of parameters is the subject of more detailed research, also in the public domain, which can be used for estimating the WACC. This second category includes the debt-to-equity ratio, the debt risk premium, the market risk premium and the value of gamma that relates to franking credits. It is worth noting that there is a high degree of consistency among regulators in Australia and elsewhere in the values ascribed to this second category of parameters.

The third category is only one parameter, beta, which is more company specific. However, where a company's stocks are not traded on the stock exchange it is not possible to obtain the necessary information to directly estimate beta for that company. In that situation it may be necessary to rely on estimating a proxy beta based on market information from another traded stock assessed as in a similar risk category as the company for which the beta estimate is required (see Section 2.3.3). A high degree of judgment is involved where proxy betas are necessary.

Essentially, the use of an appropriate proxy beta is an assessment by the Regulator concerning the amount and type of risk which an individual asset faces. If this can be accurately determined, then beta can be estimated, and validation of the remaining components of the WACC equations is relatively straightforward.

However, judging the amount of risk faced by an asset is highly problematic. Box One summarises some of the issues a regulator faces.

Box One: Why is Beta a Problem for Regulators?

In financial market analysis, beta is commonly calculated based on observed market variation, and then used to compare the relative risk of different stocks. In regulation, the assets are commonly not traded, and the Regulator instead needs to make an assessment of the relative riskiness of the asset and then use this to calculate a beta. Thus, rather than being an output, beta becomes an input into the regulator's determination of an appropriate reference tariff. Timing is also a critical issue; the Regulator determines beta and then reference tariffs for some future period (usually five years), and hence must try to 'forward-guess' the risk profile.

If a firm owning a pipeline is publicly listed, and the pipeline is its only asset, then the beta for the pipeline will be the same as that for the firm and can be estimated from stock market data. If, however, the publicly listed firm owns many different assets, it may be difficult, if not impossible, to estimate beta for any one of the several assets owned by that firm.

If the firm that owns the pipeline is not publicly listed, then there is no market-based data to rely on, and in such a situation, the only potential source of information on the "true" betas of each of the assets operated by a firm is the firm itself. The Regulator must ask the firm to provide an estimate of this beta and must then ask the firm to provide some justification for this choice. Commonly, the firm will justify the choice of beta by discussing which risks it incorporates and (implicitly or explicitly) ascribing some value to each.[18] *The Regulator then assesses the reasonableness of these claims, utilising where possible, information that can be sourced independently (for example, from pipelines which are traded).*

However, recall that information pertaining to beta provided by the firm to the Regulator is used by the Regulator as an input into the determination of the access price. It is not used to value the firm by the stock market, where analysts will examine ex-poste variation in the firm's stock price compared to market variation. Moreover, the stock market will reward a firm which provides information to the Regulator suggesting that the assets it manages are riskier than they are in reality, where this is believed by the regulator. This is because, ordinarily, returns are (inversely) related to risks, but in the regulated environment, returns (via WACC and the access price) are related to how much risk the firm can convince the Regulator it faces. If it can convince the Regulator that it faces more risk than it actually does, then its returns will increase (via an increase in the allowed access price). The stock market will reward this strategy via an increased stock price as more market players seek ownership of the assets managed by this firm, which are attaining greater revenues than would be expected, given its true risk profile.

Thus the firm managing the asset faces an 'incentive problem'; it will be rewarded by the stock market for successfully providing false information to the regulator, and punished if it provides true information (or if it provides false information which is subsequently not believed). Given that the Regulator will not believe risk claims that can be disproved by cross-checking with independent information, the best strategy for the firm to adopt is to claim risks for which limited independent information exists (or which is costly to collect). This maximises the opportunities for the firm managing the assets to be rewarded by the stock market, but also maximises the difficulty of the regulator's task.

[18] The most common approach is to use some benchmark (such as US gas firms) and abstract from this to account for some specific risks. This effectively states that the pipeline faces all the risks in the US, plus these additional risks, which may raise or lower beta.

As discussed in Box One, determination of beta in the regulatory context is highly problematic. Moreover, quite apart from the problem of sourcing sufficient independent information to assess each claimed risk, the extant academic literature provides limited assistance to the Regulator in respect of ascribing a portion of beta to each of the risks which a firm claims are faced by an asset, which is essentially what the Regulator must assess when examining the justifications provided by the firm for the beta it has claimed.

This is partially because most studies have a methodological sequence which is opposite to that of the regulator, beginning with a market-derived beta, and then seeking explanatory variables correlated with this beta, rather than beginning with risks and attempting to 'build' a beta. Further, explanatory variables used are often those such as profitability, earnings variability or leverage, which are internal to the firm.[19] As discussed previously, whilst these may be correlated with exogenous variables, they are not the same as the exogenous variables and the degree to which they are correlated may be difficult to assess, particularly on an a-priori basis.

Only a few studies consider exogenous variables as potential determinants of beta.[20] These include the incidence of regulation and shifts in input costs (such as wage rates) beyond the control of the firm. However, whilst exogenous shifts in input costs have been found to be positively correlated with movements in beta, studies of regulation have yet to yield consistent results (see Attachment One and the discussion on Regulatory risk for further details).

The APT literature explicitly considers systematic risk as the sum of a number of risk factors. Moreover, these risk factors are generally exogenous in nature, such as employment, manufacturing prices, award wages, the money supply, exchange rates and the current account deficit (Groenewold & Fraser, 1997 and Fang & Loo, 1996). Examination of many of the macroeconomic figures often considered as explanatory variables in APT regressions suggests that some of these, at least, are in-principle diversifiable. For example, shareholders are able to diversify exchange rate risk by holding stocks in overseas companies within their portfolio, or by hedging. Consistency of results is another issue; if a risk were truly systematic, then one would expect that it would be found to be so in most regressions (data limitations permitting). However, empirical APT papers often conflict in terms of the risk factors they find to be statistically significant. Even in a single study, it is sometimes found that a risk is statistically significant in some samples, but not in others, as Fang & Loo (1996) find with exchange rates.

[19] Three studies which adopt this approach are Ismail, Kim & Kirk (1994), Sudarsanam (1992) and Thompson (1976). The latter, although now somewhat dated, contains the most substantial list of internal factors potentially correlated with systematic risk.

[20] Three such studies are Riddick (1992), who examines the effect of regulation; Wong (1995), who considers market share, Tobins Q and the wage rate; and Lee, Chen & Lian (1995) who consider variation in a number of input factors.

The bottom line is that, although theories of diversification are well-developed, the theory of what constitutes a systematic risk is not. The authors of this report have considered mechanisms, grounded in economic theory, which describe how decisions of individual investors, when summed to the market, might result in the betas which are observed, and hence which might provide researchers with a theoretical basis to break beta into its constituent components. This research is ongoing, and is currently too premature for inclusion in this report. However, interested parties are directed to the IRIC discussion paper on the topic.[21]

This does not mean, however, that it is not possible to pass some comment on the various risks which have been suggested by firms managing pipelines as justification for the betas they have claimed. Table 2 (overleaf) provides a brief overview of our view of a number of commonly claimed risks, with further details outlined in Attachment One. The list of potential risks is not intended to be exhaustive. In brief, three main categories are identified:

- Risks that are systematic and hence non-diversifiable.
- Risks that are non-systematic and hence may be diversified.
- Items claimed as risks which are neither (often these are issues which are best dealt with in some other way, such as cashflow).

In examining Table 2, the distinct difference between the number of systematic risks and the amount of systematic risk an investment faces should be considered. An investment may only face a small number of systematic risks, but be highly sensitive to them, and hence have a higher beta than an investment which faces a larger number of risks, but which is relatively insensitive to them.

[21] Any comments on the paper would be welcomed at willsjon@cbs.curtin.edu.au.

Table 2 "Systematic" Risks Commonly Proposed in Submissions to regulators

Perceived Risk	Management of Risks	Systematic, Non-Systematic, or Neither
Asset stranding and bypass	Investors can address this risk through portfolio diversification. Moreover, other regulators have allowed mitigation of these risks through accelerated depreciation allowances, which is a more appropriate approach than an allowance in beta.	Non-systematic
Regulatory risk	As experience with the regulatory regime increases, the level of uncertainty and regulatory risk declines. Regulatory risk is clearly diversifiable as investors can hold stocks in both regulated and unregulated industries.	Non-systematic
Bankability, capital market adequacy and hurdle rates	These are not risks within the CAPM framework, as if a project is not bankable, or does not meet the hurdle rates of any investors, then they will not be successfully brought to market, and will not be considered by investors. Were the Regulator to consider these factors, he would be stating a willingness to intervene to provide support to render some projects commercially viable which would not be so in a competitive market. This is the role of industry policy, not regulation.	Neither
Demand risk	This is in-principle the same as the risk of asset stranding or bypass. Investors address this risk through portfolio diversification. Moreover, this risk has an upside as well as a downside. Finally uncertainty of future demand is often mitigated by requiring long-term contracts for services, requiring take-or-pay commitments and through risk mitigating tariff design	Non-systematic
Concentrated customer demand	Investors are able to diversify any additional risk that may be attributable to situations where demand is concentrated to a narrow range of end use customers by holding a diversified portfolio of stocks. Risk can also be mitigated by firms promoting long-term contracts, take-or-pay contract conditions and adopting other risk mitigating tariff design options.	Non-systematic
Greenfield developments	This is essentially the same as demand risk.	Non-systematic
Input costs	Whilst input price variation might be a systematic risk in other industries (as a number of studies have found), in regulated industries, a reference tariff is allowed to move with CPI (minus some efficiency factor). As such, general price movements are accounted for, and do not need to be allowed for in beta. Moreover, access arrangements can be reviewed at any time if the infrastructure operator believes input costs have changed.	Neither

Sovereign and political risk	Since investors are generally able to diversify their portfolio across jurisdictional boundaries, sovereign and political risk is generally diversifiable. Where sovereign and political risk affect the whole market, this would be reflected in the market risk premium and/or risk-free rate, not in beta.	Non-systematic
Global economic growth	Portfolio diversification will not reduce exposure to the risk of variations in global economic growth. Whilst it is possible to purchase futures contracts on the price movements of certain commodities, futures contracts based on the movement of the global economy as a whole are not known.	Systematic
Innate riskiness of incentive regulation verses rate of return regulation	Although a number of authors have suggested that incentive regulation is inherently more risky than rate of return regulation, views on this are divided. In any event, investors are able to diversify against all forms of regulated investments, which would categorise the risks associated with both of these forms of regulation as non-systematic.	Non-systematic
Option risk	It has been suggested that large lumpy infrastructure investments pose additional risks not adequately reflected by beta. However, from the point of view of a portfolio investor, the stocks of companies that invest in such infrastructure are tradable and hence diversifiable. Hence risks associated with such investments are non-systematic.	Non-systematic
Country risk	CAPM generally accounts for risks that pertain to an entire country through the market risk premium. To the extent that risks pertaining to a country as a whole are not reflected in this way, such risks would be non-systematic as portfolio investors are free to trade in stocks globally.	Non-systematic
Risk of investing in WA	To the extent that risks pertaining to WA are not reflected in the market risk premium, such risks are non-systematic since portfolio investors are free to diversify their portfolios globally.	Non-systematic
Risk of investment in the WA Gas Industry	Investors are not only free to diversify their portfolios across different states or countries, they are also free to diversify across different types of industry. The market risk premium reflects variations in risks between different states or countries while beta reflects variations in risk between different types of industry. To the extent that risks pertaining to WA are not reflected in the risk premium and to the extent that risks pertaining to the type of industry are not reflected in beta, as indicated by market behaviour, such risks are diversifiable and are therefore non-systematic.	Non-systematic

3.2 OTHER FACTORS

In some submissions, a case has been made for the alteration of rates of return for reasons external to the parameters directly associated with CAPM. These external issues have two components. The first of these relates to economic "externalities", which may not be priced in the market. Pollution is one common example. The second relates to the difference between static technical and allocative efficiency, and dynamic efficiency. CAPM allows for technical and allocative efficiency to be addressed, but may not provide sufficient returns to deliver dynamically efficient outcomes, if uncertainty exists in the market as to future economic directions. For example, if the market does not accurately reflect the potential for development in a region, this may be attributable to a failure of dynamic efficiency.

However, the extent of these concerns must be tempered by what generally is and what is not the role of the regulator.[22] It is not generally the role of the Regulator to deal with issues that might generally come under the headings of either "externalities" or "economic development." The role of the Regulator is to attempt to replicate the effects of a competitive market, not to attempt to augment those effects where augmentation might be considered in the public interest.

If a competitive environment does not deliver investments that would result from the incorporation of economic externalities into decisions, say through taxation or subsidies, that is no concern to the regulator. Nor is it the concern of the Regulator as to what might be politically attractive about a certain type of investment (i.e. it delivers a certain level of employment, or is located in a certain part of the State). This is not to say that competitive markets never need augmentation. In some instances, they do, and the State certainly has a role to play. However, that role is more effectively undertaken through industry policy, not through regulatory policy, as the instruments of industry policy are specifically designed for the task.

The reasons that have been cited in support of raising rates of return for reasons external to the parameters of CAPM include:

[22] We make this distinction in light of the recent Supreme Court decision in regards to the Dampier to Bunbury Natural Gas Pipeline, whereby the Court decision may require the Regulator to consider economic development and other issues, due to the existence of Section 2.24 of the Code. Whilst this decision may be correct in law, it is not, in our opinion, a good foundation for economic regulation based on sound economic principles. The issue would seem to lie in Section 2.24 of the Code, which may require revision, when next the Code is reviewed.

- Expansion of the infrastructure is critical to the development of the state/region and returns need to be sufficient to attract ongoing investment and new "greenfields" investment.
- That the regulated firm employs many people both directly and indirectly, and insufficient returns may threaten this.
- That the regulated firm contributes substantially to the maintenance of leading edge research in the field.
- The firm will no longer be profitable without higher returns, with substantial downstream and upstream ramifications for the development of the State.
- The firm can only supply new customers at a higher price, creating a group of "second class consumers".
- Low rates of return pose a health and safety risk.
- The "maturity", or lack thereof, of the gas pipeline industry.

These issues are addressed in the remaining parts of this section.

3.2.1 State & Regional Development

In public submissions, some stakeholders have suggested that the rates of return available under the CAPM methodology as applied by the Regulator may be insufficient to:

- support expansion (and in some cases, maintenance) of a pipeline;
- encourage the construction of new pipelines; and/or
- provide funds for research and development which both enhance the State (or region) and support employment.

The rate of return estimated using the CAPM represents an estimate of the opportunity cost of capital available for investment in the gas pipeline industry. Returns that exceed the WACC under CAPM exceed those available to normal investors in the stock market. Provided that the Regulator is applying CAPM correctly (which the conclusions in Chapter Two suggest is the case), these arguments suggest that rates of return available to normal investors are insufficient to support State and regional development.

While the competitive market may not provide sufficient returns in some instances, this does not imply that any such market failure, if it exists, should be corrected through regulated rates of return. If a competitive market provides insufficient returns which the community believes are of value to future economic development, a more efficient means of addressing such a deficiency is likely to be through direct government fiscal action (either through taxes or subsidies) and not through increasing returns which may further distort resource allocation. That is, State and regional economic development are issues appropriate to industry policy, not regulatory policy.

3.2.2 Insufficient Returns Hampering Profitability

The Code objective of *"Providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service"*[23] is clearly inconsistent with any perception that the rate of return under CAPM may render the pipeline-owning firm unprofitable.

Indeed, there is nothing within the CAPM (or similar asset pricing models) that would necessarily cause returns to an asset owner to be unprofitable. The rate of return under CAPM represents the opportunity cost of capital. It is the rate paid by borrowers for the use of funds and it is set in a very competitive market environment. The suggestion that the rate of return under CAPM is unprofitable is, in effect, to suggest that market returns are unprofitable for a particular project.

This may be the case. If so, and the community would benefit from such an unprofitable project (in that the social benefits demonstrably outweighed the social costs at the margin), then this is a prima facie case for government intervention, but through the instruments of industry policy, not through regulatory policy.

3.2.3 The Creation of a Group of "Second-Class" Customers

In most Access Arrangements, restrictions are not placed on the on-selling of access rights. Indeed, many pipeline operators actively seek to establish secondary markets to encourage such trading (and to maintain high use of the pipeline). Such secondary markets render price discrimination, and hence the creation of a situation where new customers pay more for access than existing customers, difficult.

For example, if a pipeline operator was charging $1 per GJ for access to existing customers, and decided to charge $1.50 to new customers, then existing customers would have a very strong incentive to sell some of their capacity in secondary markets for less than $1.50.[24] Indeed, both the theory and empirical evidence of

---

[23] Code Section 8.1(a).

[24] We recognise that if existing customers have no spare capacity **and** the marginal value of their capacity allocation in use is greater than the profits they could obtain from trading in a secondary market, then arbitrage would not occur. However, the very fact that secondary markets are proposed suggests (at least in the expectations of the pipeline operator proposing them) that that this situation is unlikely to eventuate.

the operation of markets suggests that arbitrage opportunities such as this are soon competed away, leaving both existing and new customers facing the same price. For this reason, it is difficult to conceive how a coterie of 'second-class customers' could develop, unless a pipeline operator restricts the ability of customers to on-sell capacity.

3.2.4 Health and Safety Issues

Some stakeholders have suggested that inadequate rates of return, leading to lower revenues, could leave firms with insufficient funds to adequately cover their health and safety obligations. Any resultant accident that may occur could have substantial ramifications, not only for the firm, but also for the State as a whole.

The Regulator is not responsible for the oversight of health and safety issues. This is the responsibility of the Department of Industry and Resources. However, health and safety obligations are an operational and/or capital expense, legitimately addressed through the cash-flow of the pipeline owner. Provided adequate allowance is made in the cash-flow, there should not be a need for higher rates of return.

3.2.5 The Maturity of the Gas Industry

A recent critique of infrastructure provision in Australia has suggested that infrastructure in the gas industry is immature, and that regulators are imposing regulatory frameworks more suited to mature North American and European markets, which do not take into account the higher risks present in Australia.[25]

The view that the gas industry in Australia is immature and in need of support is similar in nature to the "infant industry" argument, popular amongst some trade policy advocates in the 1960s.[26] Essentially, both the infant industry argument, and the view that the gas industry in Australia is immature are based on the premise that the industry has substantial potential, but that this potential is yet to be fully realised by markets. For this reason, markets do not provide sufficient returns to those investing in them, and hence investment is insufficient, and the potential is not realised.

It may be the case that market returns are insufficient to attract sufficient investment to the industry, although the findings of Chapter Four, and recent

[25] Australian Infrastructure Report Card Alliance, 2002, p90.

[26] The concept has now largely fallen from favour as experience has shown that infant industries have become reliant on subsidies. Indeed, international experience suggests that subsidised infant industries may become less efficient over time.

media and other comments suggest that this may not be the case.[27] If, however, insufficient investment is taking place, the problem is in the nature of market failure that is better addressed by government directly targeting the specific areas or projects which are the subject of such market failure through industry policy, and not through regulatory policy.

3.2.6 Funding of New Projects

Rates of return under CAPM provide a market based return to compensate investors for the equity invested and to cover the cost of debt. Investors are free to reinvest part or all of the return on equity and the amounts generated by cash flows in the form of return of capital (e.g. depreciation).

The view that rates of return should be set above market rates to provide additional funds for investment in new projects is tantamount to seeking a subsidy to encourage investment in the industry. As the merits of subsidies to encourage investment are matters for consideration by Governments, such subsidies are more appropriately administered by Governments targeted to address the specific areas of need; that is, through industry policy, not regulatory policy.

[27] McCarthy (2002) in the *Herald Sun* quotes the managing director of Origin Energy, who accused the gas industry of "grossly over-estimating the future demand for gas". The ACCC (2002b, p9) has suggested that recent rates of returns granted by Australian regulators to owners of regulated gas pipelines have not hindered the development or proposed development of new pipeline infrastructure.

4 COMPARISONS OF RATES OF RETURN

This chapter provides comparative information on rates of return available to a variety of industries in Australia, including the gas transmission industry. It also provides a brief overview of rates of return available in gas transmission industries overseas. Comparing rates of return between different political or regulatory jurisdictions in Australia and in other countries and between different industries is both difficult and fraught with hazards that can lead to inappropriate or inaccurate conclusions. As a consequence, it is not the purpose of this chapter to draw definitive conclusions from the rate of return comparisons presented, but to provide information and discussion on the material available.

The reasons why rates of return do not readily lend themselves to being compared across jurisdictions and between different industries are numerous and include:

- component parameters such as the risk-free rate and inflation vary over time with the result that rates of return are not directly comparable unless made at similar points in time (or at least the business cycle);
- component parameters such as the debt-to-equity ratio will vary between firms, industries and jurisdictions; and
- industry composition, which tends to differ between countries.

The following discussion will not address each of the individual elements of the rate of return (such as market risk premium, risk-free rate etc). The focus is rather on overall rates of return.

4.1 RECENT COMPARISONS OF RATES OF RETURN

In a study commissioned by the ACCC, National Economic Research Associates (**NERA**) concluded that (NERA 2001a p2):

> Australian regulators are, if anything, declaring higher Vanilla post-tax WACCs than in other jurisdictions examined. Purely based on the declared returns examined in this survey, Australian regulators appear to offer approximately the same or higher returns than North American regulators who in turn appear to offer significantly higher rates of return than in the United Kingdom.

NERA's results, in respect to rates of return, are summarised in Table 3.

Table 3 Average Real Post-Tax Rates of Return Across Jurisdictions

	North America	United Kingdom	Australia
Return on Equity	8.8%	6.9%	10.1%
Return on Debt	4.8%	4.4%	4.6%
Vanilla WACC	6.6%	5.6%	6.8%

Source: NERA 2001a.

By comparison, the Western Australian Gas Access Regulator has determined an average return on equity of 10.6 percent; an average return on debt of 4.5 percent and an average Vanilla WACC of 7.0 percent in respect of the three final decisions and two draft decisions issued in this State.

In response to the NERA paper, Network Economics Consulting Group Pty Ltd (**NECG**) issued a paper in July 2001 strongly refuting any implication that NERA had shown that determinations by Australian regulators are generous in international terms. NECG indicated three key failings in NERA's analysis (NECG 2001):

- selectivity and bias in the sample of UK regulatory decisions that are examined, which serves to misrepresent UK experience as being consistent with a set of relatively harsh cost of capital determinations;
- omission of any analysis in differences in country-specific risks, which we believe can fully account for the apparent differentials in allowed rates of return across the three jurisdictions; and
- omission of any detailed discussion of differences in the three regulatory regimes, the impact of those differences being to expose utilities in Australia to greater risk than their counterparts in the UK and US.

In response to NECG's comments on bias, NERA makes the point that the average rates of return compared across jurisdictions were limited to energy alone and to suggest that such bias would be reduced by adding rail, telecommunications and air traffic control decisions to the UK side of the sample is preposterous (NERA, 2001b). Certainly, from a statistical perspective, simply adding more observations does not necessarily reduce bias, if the additional observations are drawn from a different population.

On country specific risk, whilst it is true that replacing the risk-free rate and market risk premium used in UK and US decisions with those used in Australian decisions would result in calculated WACCs being more closely aligned, this does not mean that a 'country risk premium' needs to be factored in to beta, as it is already included in the risk-free rate and market risk premium. Thus, it would not be correct to use the NECG paper as justification for a higher beta, nor does NECG claim that this is the case.

On differences in regulatory regimes, NECG makes a claim that differences matter, but provides limited support to its arguments. Other analysts have found that regulatory regimes have limited effects (see Attachment One). On the more specific issue of the manner in which asset values are calculated, whilst we would agree this may be an issue for regulated firms, we do not agree that it should be addressed by increasing rates of return (see Attachment One and the discussion on asset stranding).

The essential message from examining the debate between NERA and NECG is precisely the one which both parties propose; that simplistic comparisons of rates of return allowed in regulated industries in different national jurisdictions does not add substantially to the rigorous assessment of the 'reasonableness' of rates of return offered in a particular jurisdiction.

In a recent study comparing equity betas for a range of companies in the US, UK and Australia, the Allen Consulting Group (**ACG**) noted that (ACG, 2002 p47):

> … 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,….,the current evidence suggests regulators systematically have erred in the favour of the regulated entities.

Table 4 Average Asset Beta Estimates

	Tax Term Excluded from Levering Formula		**Tax Term Included in Levering Formula**	
Beta Estimate	**Debt Beta = 0**	**Debt Beta = 0.15**	**Debt Beta = 0**	**Debt Beta = 0.15**
Australian Companies	0.27 (0.27)	0.35 (0.35)	0.30 (0.30)	0.37 (0.37)
USA Companies	0.06 (0.10)	0.13 (0.17)	0.07 (0.11)	0.13 (0.17)
Canadian Companies	0.01 (0.09)	0.10 (0.19)	0.01 (0.11)	0.09 (0.20)
UK Companies	0.06 (0.12)	0.11 (0.16)	0.06 (0.13)	0.11 (0.16)

Source: ACG 2002.

Table 4 shows the implied simple average of the asset betas for groups of selected firms in each of the markets, for different de-levering assumptions described in section 3.3 of the ACG report (with the figures in parentheses showing the averages when the firms with negative beta estimates are excluded). The firms in each group were selected by ACG on the basis of a hierarchy of 'comparable activities' in regulated transmission and distribution industries as discussed in section 4.1 of the ACG report.

For Australian companies, including a debt beta of 0.15 and including taxation in the levering formula, the average asset beta is 0.37.

The asset betas adopted by the Western Australian Gas Pipelines Access Regulator in both draft and final decisions are in the range 0.55 for gas distribution to 0.65 for gas transmission pipelines using a debt beta of around 0.2.

The asset betas adopted by the Western Australian Gas Pipelines Access Regulator are therefore well above those estimated by ACG for listed companies in the US, Canada, UK and Australia. However, the caveat of comparing like with like remains; allowing higher betas for WA would be overly generous only if the exposure to systematic risks of investors owning infrastructure in WA was not substantially higher than the exposure to systematic risk of an investor in other jurisdictions.

4.2 RATES OF RETURN IN AUSTRALIAN REGULATED INDUSTRIES

There is now some history of regulatory decisions in Australia for gas pipeline and distribution networks. However, a simple comparison of rates does not provide an appropriate basis from which conclusions can be drawn concerning the adequacy of such rates. Apart from differences in the values of parameters that are used in determining regulated rates of return and differences in the methodologies used, comparisons of declared rates of return also belie possible differences in markets and regulatory regimes which could be important determining factors in considering differences between jurisdictions. Accounting for such differences is likely to require complex modelling, which is beyond the scope of this paper. While it is recognised that simple comparisons of declared rates of return fall well short of that required, these are presented for the sake of completeness.

Declared rates of return by Australian regulators are summarised in Table 5 below, which indicates that decisions by the Western Australian Regulator on rates of return have been towards the upper end as compared with decisions by other regulators around Australia.

Table 5 Declared Rates of Return for Gas Transmission and Distribution – Australia

Regulatory Decision	Regulator	Date	WACC[28]
Central West Final Decision[29]	ACCC	June 2000	7.78%
Victorian Transmission System[30]	ACCC	October 1998	7.75%
Moomba to Adelaide Final Decision[31]	ACCC	September 2001	7.14%
Amadeus Basin to Darwin Final Decision[32]	ACCC	December 2002	6.75%
AGL Gas Networks Final Decision[33]	IPART	July 2000	7.75%
Albury Gas Company Final Decision[34]	IPART	December 1999	7.75%
Great Southern Final Decision[35]	IPART	March 1999	7.75%
Envestra Final Decision[36]	SAIPAR	December 2001	7.6%
Multinet, Westar & Stratus Final Approval[37]	ORG	December 1998	7.75%
Tubridgi Final Decision[38]	O*ff*GAR	October 2001	8.2%
Parmelia Final Decision[39]	O*ff*GAR	October 2000	8.1%
Alinta Final Decision[40]	O*ff*GAR	June 2000	7.55%
GGT Draft Decision[41]	O*ff*GAR	April 2001	7.95%
DBNGP Final Decision[42]	O*ff*GAR	May 2003	7.4%

Source: Various Draft and Final regulatory Decisions.

28 Real pre-tax.

29 ACCC (2000a) p48.

30 ACCC (1998) p63.

31 ACCC (2001a) p54.

32 ACCC (2002e) p96.

33 IPART (2000) p70

34 IPART (1999b) p32

35 IPART (1999a) p39

36 SAIPAR (2001) p88

37 ORG (1998) p7

38 OffGAR (2001a) p31

39 OffGAR (2000a) Part B p91

40 OffGAR (2000b) Part B p105

41 OffGAR (2001b) Part B p120

42 OffGAR (2003) p78

4.2.1 Stock Prices for Listed Gas Pipeline Companies

If returns to investors in gas pipelines were judged by investors to be insufficient, then it might be expected that investors would demand fewer shares, and hence that stock prices of companies operating regulated gas industry assets would either fall in absolute terms, or in relation to shifts in the All Ordinaries Index. Of the pipelines regulated by the WA regulator, only Alinta is traded directly in the stock market.

Four gas pipeline companies are traded on the Australian stock market; the Australian Pipeline Trust, Alinta, Envestra and United Energy. Apart from a brief period in November/December (longer for Alinta), all outperformed the All Ordinaries Index in the six months from October 2002 to April 2003.[43] Although it may be the case that these regulated firms are managing to improve their performance despite regulation, the fact that they have performed better than average makes it difficult to conclude that gas pipeline regulation in Australia is impeding the ability of firms to attract investors, based on stock price performance. In the absence of detailed analysis of stock price movements and their determinants, which is beyond the scope of this report, it is difficult to be more definitive.

Finally, there is some evidence to suggest that the expectations of investors in regards to future stock market returns has trended downwards in recent months. James (2002), writing in the *Financial Review* foreshadows an average return on Australian shares of only 9.5 percent, and quotes AMP projections of 8.5 percent returns on equity over the next ten years.

4.3 RATES OF RETURN IN OTHER AUSTRALIAN INDUSTRIES

Comparison of rates of return as set by the different regulators in Australia is, in a sense, incomplete because this does not shed any light on whether such rates of return reflect reasonable market expectations. Regulators around Australia, as discussed in Chapter Two, adopt very similar methodologies in the calculation of rates of return. Indeed, parameters tend to vary only in time, and to a much lesser extent, as between regulators at any point in time. For this reason, the similarity in the rates of return shown in Table 5 may not be particularly surprising.

[43] Price history data were sourced from the ASX website: http://www.asx.com.au/asx/homepage/index.jsp. In an earlier draft of this report, we examined performance of the four companies from Mid 2001 to first quarter 2002. During this period, all four companies generally outperformed the All Ordinaries Index, with the exception of United Energy in the first quarter of 2002.

While it would be interesting to examine how rates of return determined by regulators compare with those available in the broader market, no suitable comparisons are immediately available. There are, however, published reports by the Australian Bureau of Statistics (**ABS**) providing summaries of industry performance that include estimates of returns on capital and equity (ABS, 2001). While these publications by the ABS are of interest in themselves, the rates of return are not directly comparable to the rates of return determined by regulators. In particular, the historical record of the five years to 2000 may be very different to the future, and the Regulator determines WACCs on a forward-looking basis. However, an examination of historical rates of return in different industries does shed some light on the question of whether Australian regulators have been 'reasonable' in past decisions.

Table 6 presents a five year summary of the return on assets, the return on net worth, average cost of capital, the gearing ratio and the ratio of current liabilities as a proportion of total liabilities for Australian industries over the period 1995/6 to 1999/00.[44] While the table does not provide a firm basis for comparing rates of return with those approved by regulators, the table does provide some insight on the relative rates of return as between the different industry classifications listed. Exceptional returns on net worth (greater than 15 percent) are indicated in bold type.

[44] The return on assets is defined as the operating profit before tax as a percentage of the total book value of the assets. Return on net worth is defined as the operating profit before tax as a percentage of the value of shareholders funds. Shareholders funds are defined as total assets less total liabilities. Cost of debt is defined as total interest expense as a percentage of total liabilities. The gearing ratio is defined as total liabilities (excluding shareholders funds) as a percentage of total assets.

Table 6 Returns & Gearing Australian Industry 1995/6 to 1999/00

Industry Class	5 Year Simple Average				
	Average Return on Assets (%)	**Average Return on Net Worth (%)**	**Average Cost of Debt (%)**	**Gearing (%)**	**Current Liabilities on Total Liabilities (%)**
All Industries	4.2	12.9	4.2	67.5	n/a
All Industries excl Agriculture, Forestry & Fishing	4.3	14.5	4.1	70.6	n/a
Agriculture, Forestry & Fishing	3.1	3.7	7.1	17.4	41.3
Mining	8.3	**20.8**	3.4	60.1	37.7
Manufacturing	7.1	**16.8**	3.4	57.2	56.3
Electricity, Gas & Water Supply	3.6	6.5	6.4	44.5	21.0
Construction	10.5	**34.0**	3.0	69.1	59.8
Wholesale Trade	8.0	**24.9**	3.0	68.0	78.3
Retail Trade	10.7	**34.4**	6.4	68.4	66.8
Accommodation, Cafes & Restaurants	5.7	12.3	4.9	53.4	38.5
Transport & Storage	5.1	12.9	4.3	60.1	38.8
Communication Services	11.2	**25.7**	3.7	56.9	48.4
Finance & Insurance	2.4	12.7	4.1	80.9	n/a
Property & Business Services	5.6	11.3	5.4	50.9	52.9
Private Community Services	10.1	**19.2**	3.2	47.2	44.1
Cultural & Recreational Services	6.5	13.8	3.0	54.3	46.0
Personal & Other Services	7.1	10.3	4.1	30.8	52.0

Source: Australian Bureau of Statistics, 2001, Summary of Industry Performance, ABS Cat no 8140.0.55.002 Final 2000/01. n/a: not available.

On average, firms across all industries over the five year period achieved a nominal pre-tax return on net worth of 12.9 percent based on a gearing ratio of 67.5 percent. The pre-tax return on assets averaged 4.2 percent. It should be noted, however, that the real pre-tax WACC within the regulatory context is generally comparable (in terms of its method of calculation) to the ABS definition of return on assets.

The electricity, gas and water supply industry has amongst the lowest rates of return in Table 6. However, one must be careful in drawing strong conclusions about the effect of regulation on this. In the first instance, the inclusion of the water sector, dominated by publicly owned utilities, doubtless reduces the average. Also, based on Table 5, the WA Regulator has allowed an average real pre-tax WACC of 7.84 percent in recent decisions (10.51% nominal pre-tax). Thus, the Regulator has calculated access reference tariffs based on a WACC of almost twice the average actual rate of return on assets made in the market over the five year period shown.[45] If gas pipelines were comparably more risky than the stock

[45] We concur that the past need not be a realistic guide to the future in terms of returns. However, we note that the period of the ABS sample partly covers a period of historically high returns in

market average, then this would be appropriate. However, no pipeline operator has suggested an asset beta of greater than one (by definition, the market average) in any Access Arrangement proposal in WA. Although by no means conclusive, it is difficult to conclude, on this basis, that the Regulator is restricting returns possible for pipeline operators through setting WACC 'too low'.

The evidence on returns on net worth (approximately equivalent, definitionally, to returns on equity within the regulatory context) is mixed. The Regulator has allowed an average real pre-tax return on equity of approximately 12.9 percent. This is the same as that actually achieved by an average Australian business in the five years to 1999/2000. Moreover, a particularly distinguishing feature of Table 6 is that where returns on net worth are high (above 15 percent) the average cost of debt is low in nearly all cases (less than four percent). On examination, the relatively low average cost of debt is generally associated with a relatively high ratio of current liabilities to total liabilities (above 45 percent). In addition, the high rates of return on net worth also appear to be associated with a relatively high gearing ratio (above 60 percent). This suggests that firms achieve high returns on equity by combining a relatively high gearing ratio with a relatively high proportion of non-interest bearing liabilities. While this result is not conclusive, it indicates that returns to equity, as measured by aggregate statistics, may reflect particular financial strategies adopted by firms. On this basis, it renders comparison between aggregate measures of return on net worth and returns on equity used in regulatory reference tariffs determinations difficult. This is certainly an area worthy of further research.

4.4 INTERNATIONAL COMPARISONS OF RATES OF RETURN

It should be noted at the outset that international comparisons of rates of return are, if anything, more fraught with difficulty than domestic comparisons, due to the more substantial underlying differences between the Australian and other international economic and regulatory structures. As NECG and NERA have both noted, short of detailed modelling designed specifically to account for these differences, comparison between nations should be made advisedly.

However, it is useful to examine returns available elsewhere in the world. Partially, it provides a very rough 'ballpark' estimate of ranges within which rates of return should lie to make the gas industry in WA competitive with those elsewhere in the world. Also, it allows one to begin an analysis of the opportunity costs of investing in WA, by asking the very broad question of "if these firms

the Australian stock-market, and it generally accepted that the near future will not match returns made in the late Nineties.

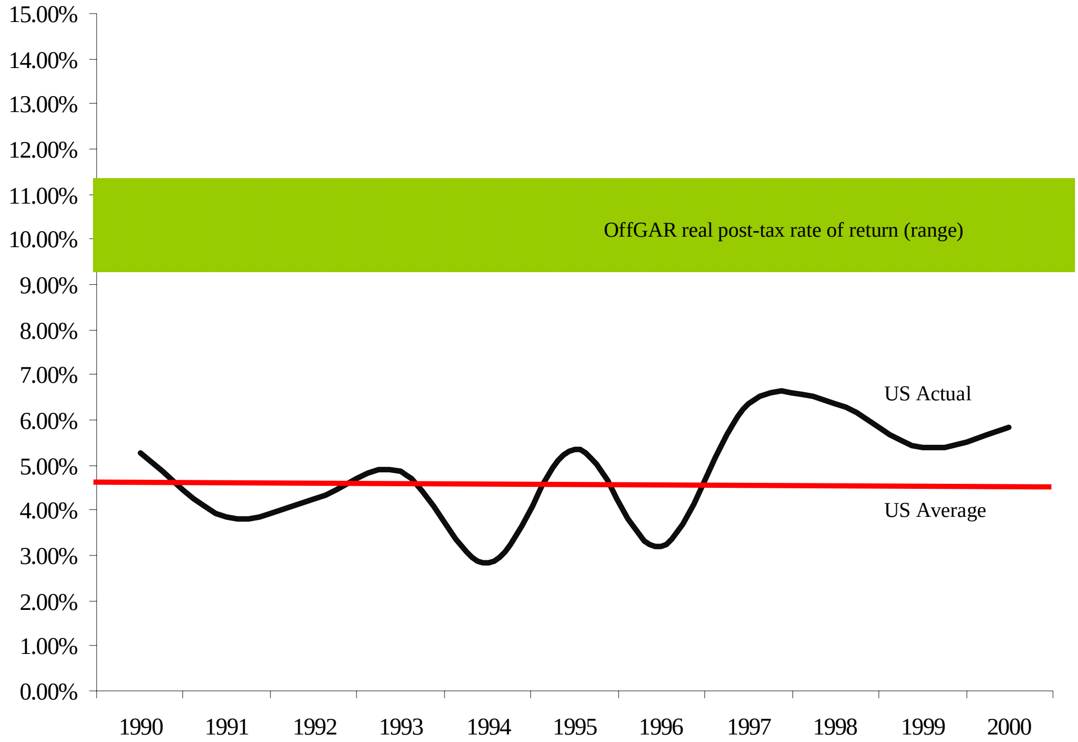
were to withdraw their investments from WA, what kind of returns could they earn in a similar industry elsewhere in the world?"

Naturally, when examining global markets, the scope for examples and discussion of their relevance becomes almost limitless. It is not intended that this paper detail a large number of cross-country comparisons. The NERA-NECG papers already provide some comparisons. We supplement these with an examination of the actual performance of the US gas market over the past decade, and of a series of Canadian regulatory decisions.

Figure One examines the actual returns on equity made in the US natural gas pipeline industry, from annual report data filed with the Federal Energy Regulatory Commissioner.[46] Superimposed on Figure 1 is the range of post-tax real return on equity determinations by the Regulator (green band), and a line indicating the US average over the decade of 4.8 percent (red line).

[46] The rate of return is calculated as the net, post-tax income divided by the total asset value (and converted to percentage form) for each pipeline. Annual rates of return are an unweighted average of returns for each pipeline. The FERC data do not specify whether asset values are in real or nominal terms, but from the context of the data provided, it would appear that the values are in real terms.

Figure 1: US Gas Pipeline Actual Returns on Equity (1990-2000) Compared to Returns Provided by the WA Regulator



Source: FERC Major Natural Gas Pipeline Annual Report Form 2 (http://www.ferc.gov/docs-filing/eforms-gas.asp#2)

The WA Regulator is thus allowing returns on equity which are approximately double (on average) of those actually achieved by gas pipeline firms in the US. However, return is correlated with risk, and if an investment involves more risk, one would expect the cost of capital to be higher. In order to establish the appropriateness of the rates of return offered by the Regulator with sufficient rigour, one would need to conduct a detailed review of the risk (or beta) of all of the pipelines in the FERC sample and those of WA. Not only is such a detailed analysis beyond the scope of this report, but it is not possible, as the pipelines in WA are assets which are not traded in the marketplace.[47] However, Table 4 suggests that, if assets with negative asset betas are excluded, Australian energy

[47] This may also be the case with some of the pipelines in the FERC sample.

companies are roughly twice as risky as their American counterparts. Thus, on the basis of a very superficial comparison, it would appear that returns available for investors in gas pipelines under regulation in WA compare reasonably well with those actually achieved in the US marketplace.[48]

In a recent report, the International Energy Agency (IEA) (1998, Chapter 18) describes the Canadian gas market as “probably the most unfettered and most competitive gas market in the world”, which is the result of government policies relying on market forces and deregulation. At the time of the IEA report, rate of return regulation was the predominant form of regulation in Canada. In Canada, rate of return regulation involves calculating a cost of service, which includes the cost of gas purchases, depreciation, income taxes, operating and administration costs and the cost of capital. This latter item comprises two elements, an allowance related to the cost of debt (essentially the cost of interest on long and short-term debt) and an allowance such that shareholders will be able to earn a “reasonable” return on capital invested. “Reasonableness” involves a judgemental assessment by the relevant regulatory board, and is based on numerous factors, including returns on alternative investment opportunities of a comparable risk and the level of return necessary to attract capital (IEA, 1998, Chapter 18). Table 7 provides a summary of allowed rates of return on equity. The IEA report (from which these figures are derived) does not explicitly identify whether the relevant rates of return are pre-tax or post-tax, or whether they are real or nominal.

[48] Replacing the Regulator’s determination for asset beta in a number of regulatory decisions in WA with the asset beta of 0.17 from Table 4 produces a post-tax real return on equity of just over four percent, which is slightly lower than that achieved in the US. However, such simplistic remodelling of results is unlikely to reflect the true differences between the WA and US markets. Most obviously, the FERC sample and the AGC sample are not likely to be the same.

Table 7 Approved Rates of Return on Common Equity Major Canadian Natural Gas Distribution Companies (1992-97) (%)

	1992	**1993**	**1994**	**1995**	**1996**	**1997**	***Average***
BC Gas	12.25		10.65	12.00	11.00	10.25	*11.23*
Pacific Northern	12.8	12.8	11.5	12.8	11.8	11.0	*12.08*
Centra Gas BC	13.0	13.0	11.1	12.5	11.5	10.9	*12.00*
Canadian Western Natural Gas	12.3	12.3	12.3	12.3	12.3	12.3	*12.25*
Northwestern Utilities	13.8	11.9	11.9	11.9	11.9	11.9	*12.19*
Centra Gas Alberta	13.3	13.3	13.3	12.0	11.8	11.8	*12.54*
Centra Gas Manitoba	12.6	12.1	11.3	12.1	11.3	10.6	*11.66*
Consumer Gas	13.1	12.3	11.6	11.7	11.9	10.3	*11.81*
Union Gas	13.5	13.0	12.5	11.8	11.8	11.0	*12.25*
Centra Gas Ontario	13.5	12.5	11.9	12.1	12.1	11.3	*12.22*
Gaz Metropolitan	14.0	12.5	12.0	12.0	11.5	10.8	*12.13*
Gazifere	14.0	12.5	12.3	12.3	11.8	11.8	*12.42*
Average	*13.17*	*12.55*	*11.84*	*12.11*	*11.70*	*11.13*	12.08

Source: IEA (1998) Chapter 18

In comparing allowed rates of return in Canada with those offered by the Regulator in WA, a difficulty is the uncertainty as to whether the Canadian return on equity figures are pre or post tax, nominal or real. By way of comparison, the average rates of return offered by the WA Regulator are as follows:

- Average post-tax real return on equity: 10.42 percent
- Average pre-tax real return on equity : 12.90 percent
- Average post-tax nominal return on equity: 13.26 percent
- Average pre-tax nominal return on equity: 15.81 percent

These averages suggest that the returns on equity offered by the Regulator in WA are roughly comparable to, and may in fact be better than, those offered by Canadian regulators.

5 CONCLUSIONS

This report has examined the methodologies utilised and results obtained by the Office of the Gas Access Regulation in WA in determining rates of return for tariff setting purposes for regulated gas pipeline infrastructure in the State. The report makes a number of important findings:

- Although some problems exist, the CAPM remains the most common and, from a data availability and implementability perspective, most appropriate mechanism for use in the regulatory framework in WA. This does not, however, imply that it must be used by pipeline owners.
- The Regulator is applying the CAPM framework and calculates the various parameters within this framework in an appropriate manner, consistent with its application in other Australian jurisdictions.
- The appropriate treatment of systematic risk in the regulatory context is still in its infancy. As an aside to this report, some theoretical approaches have begun to be developed which should assist in the future. However, for the present, the approach of the WA Regulator appears consistent with those used elsewhere.
- Many of the arguments commonly made for raising beta have limited relevance, as they deal with issues which are not systematic risks. In fact, the number of systematic risks is very small.[49]
- Very few other representations made by industry for raising rates of return (such as supporting industry) are convincing, and in general, represent a case for appropriate industry policy, not for changes in regulatory policy.
- Whilst comparisons of regulated rates of return in jurisdictions in Australia and overseas are fraught with difficulties, and much more complex than the relatively simple analysis of this report, on the basis of available evidence, it is difficult to conclude that the rates of return being utilised by the WA Regulator are below the opportunity cost of capital for the gas pipeline industry.

[49] This does not necessarily imply that the size of systematic risk is small, only that the number of individual risks which comprise it is small.

6 ATTACHMENT ONE

6.1 COMMONLY PROPOSED RISKS AND THEIR SYSTEMATIC OR NON-SYSTEMATIC NATURE

This appendix considers some of the issues underpinning the conclusions reached in Table 2, which summarises an analysis of risks commonly cited as warranting a higher beta for rate of return calculations. The conclusions of Table 2 indicate that the risks analysed are shown to be clearly systematic in only a few cases. In other cases, the risks are either diversifiable or can be managed in some way other than through beta. There are also some cases where the identified risks are neither systematic nor non-systematic.

The list of risks considered below is not intended to be exhaustive, but rather, representative of arguments that have been raised in proposed access arrangements or the associated public consultation forming part of the regulatory process to date.

6.1.1 Asset Stranding and Bypass

Natural monopoly infrastructure normally involves the commitment of large sums of money that once spent is sunk. Such expenditure, coupled with often very long operational life-spans, means that a potential investor faces the risk that, during the course of its operational life, the asset could become stranded. This could occur for a number of reasons:

- New technologies could render the type of capital employed inefficient, replacing it with more efficient technology.
- New technologies could reduce the cost of the type of capital employed increasing the risk of bypass.
- Consumer demands could change, either in nature or in location, such that the asset is no longer able to serve them. This could render the asset totally stranded (industrial area atrophication for example) or partially stranded (a major customer ceases operation).
- Competition from close substitutes could result in substitution away from the product supplied by the monopoly infrastructure.

The above risks are faced by all firms, but an important feature for natural monopolies is the need to commit large sums of money, which not only create barriers to entry, but also represent a barrier to exit. Investments, once made, can be costly to walk away from. The risk of asset stranding is sometimes put forward as a reason for higher rates of return.

However, rates of return are not the only means of addressing the risk of asset standing. This risk can, for example, be mitigated through accelerated depreciation or through long-term contracts. Moreover, addressing asset stranding through rates of return introduces substantial difficulties in future regulatory periods. For example, if the Regulator allows an extra two percent, say, in the current regulatory period to account for the risk of future asset stranding and the asset does not become stranded, then logically, the Regulator would need to reduce rates of return in the future to account for the fact that pipeline operators had been able to earn additional returns to compensate for the stranding of an asset which had not subsequently been stranded (moreover, the reduction would need to be greater than two percent, to account for the effects of discounting). A problem arises in determining sufficient evidence that an asset which had previously been considered subject to stranding was no longer subject to that risk. If, for example, the Regulator determined that the asset would become stranded in ten years, and it did not by year 10, the pipeline operator may be able to mount a credible 'wait and see' case, thus extending returns. Further complications would arise if the asset were sold in the intervening years, as the new owner might also expect to receive an allowance in rates of return to account for the risk of asset stranding, regardless of whether this risk had been accounted for in the price it paid for the asset (a factor not observable to the regulator). On balance, it would seem that allowing for asset stranding risk in rates of return potentially creates more problems than it solves.

The risk to an investor of one asset becoming stranded can be ameliorated by that investor holding a diversified portfolio of assets. Hence, it is difficult to consider asset stranding as anything other than a diversifiable risk. Whilst we recognise the importance of asset stranding, we would thus suggest that some cash-flow based method (such as accelerated depreciation) is both simpler and less subject to potential regulatory gaming than allowing for the risk in rates of return.

There is also a need to give recognition to the symmetry of risks. Whilst it is true that an asset can become stranded due to a decrease in demand, it can also earn greater than expected returns due to an increase in demand. Moreover, it is important to recognise that the role of the Regulator is to replicate the effects of a competitive market. In a competitive market, those left holding assets which become stranded due to any of the four reasons detailed above are generally not compensated by the market for their losses. Indeed, if they were, the added costs would slow the progress of change and innovation in the economy. Thus, excepting in the case where asset stranding is caused by regulatory action, regulators should consider the costs to efficient resource allocation throughout the economy as a whole inherent in allowing monopoly infrastructure operators to recover costs associated with stranded assets, above and beyond those which they would be able to recover in a competitive market.

6.1.2 Regulatory Risk[50]

Submissions by infrastructure owners often raise the incidence of regulatory risk, and of uncertainty of future regulatory treatment. Some submissions have also made mention of risks associated with the immaturity of gas regulation in Australia and a lack of consistency across jurisdictions in Australia.

Essentially, the issue is one of market uncertainty about the future decisions of the Regulator and demands for a premium to compensate for this uncertainty.

The literature identifies two types of regulatory risk. NERA (2002) has identified these to be regulatory system risk and regulatory intervention risk. Regulatory system risk concerns the relationship between the regulatory system and the cost of capital consisting of the following:

- regulation vs competition;[51]
- type of regulation (incentive based or rate of return);[52] and
- political risk.

Regulatory intervention risk, on the other hand, includes:

- predictability of regulatory behaviour (ie risk of unanticipated regulatory decisions);
- regulatory asymmetries (risk of excessive clawback); and
- impact of the price review process ("sawtooth" effect).

Empirically, the incidence of regulatory risk is far from clear. Some studies have shown that regulatory risk is not a factor determining systematic risk, as stockholders are able to predict the likely actions of the regulator.[53] This is especially the case where regulatory regimes have achieved a degree of maturity. Other studies have shown (particularly in newer regimes) that regulation can have an impact on systematic risk, with APIA (1998) citing OXERA research which suggests regulatory risk adds 1.3 percent to the required rate of return in the US. It would appear, on balance, that regulatory risk is a function of market experience with the regulatory regime Gandolfi, Jenkinson & Mayer (1996) find that

[50] For a more detailed discussion of regulatory risk see NERA (2002).

[51] See ACG (2002).

[52] See also Productivity Commission (2001, pp 353-356).

[53] For example, Fraser & Buckland (2001), who find that political events have a much greater impact than regulatory effects, Deitrich & Heckerman (1983), who suggest that cost structure and corporate growth have a much greater impact than regulatory risk, and Devany (1991), who suggests that the degree to which regulation affects risk depends upon the type of regulator, with elected regulators having a greater impact than appointed ones.

regulation induces a saw-tooth pattern on asset betas where reviews are conducted periodically, with low betas just after a decision, and beta rising as investors approach the next regulatory decision and the market is unsure of the nature of the regulator's decision. Finally, Norton (1985) & Riddick (1992) show that regulation can actually reduce systematic risk.

Regulatory risk is a product of information asymmetry in the market. Morana & Sawkins (2000) examine the English and Welsh water industries which shows that share price volatility of firms in the industry decreased after a key regulatory decision was taken in 1994, and that volatility during and relative stability after a regulatory decision is a common phenomenon. This suggests that the market incorporates the information in a regulatory decision relatively rapidly, and that any regulatory risk will dissipate relatively quickly as participants observe regulatory decisions. The fact that the market is uncertain just prior to a regulatory decision does not mean that the Regulator should take this uncertainty into account when determining beta. Just prior to a regulatory decision being made public, the Regulator is in the (unusual) position, of having more information than the market; the information about the nature of its regulatory decision. It would be inconsistent for the Regulator not to use this information in the formation of beta, particularly when the market will absorb the information contained in a regulatory decision very soon after the said decision is made public, as indicated by the results of Morana & Sawkins (2000) and Gandolfi et al (1996).

A related issue to regulatory risk is stability in the regulatory environment. Some stakeholders have argued that changes in the regulatory environment increase uncertainty, and hence should be reflected in beta. Changes in the regulatory environment are brought about through the political process. This represents a sub-set of sovereign risk. From a global perspective sovereign risk is a non-systematic risk and is discussed further below. Where the Regulator introduces changes, although these may be unknown to the market prior to their implementation, they are not unknown to the regulator. Again, the Regulator should make use of all information available to it in making regulatory decisions on beta. Moreover, allowing an increase in beta 'just in case' the regulatory environment changes ignores the issue that a change might actually reduce risks associated with infrastructure investments, which would (by the logic of 'just in case' adjustments to beta) require a lower beta. Unless all regulatory change affected beta in the same direction (which is not supported in the literature), then it is difficult to ascertain whether a change in beta 'just in case' the regulatory environment changes should result in an increase or a decrease in beta. Thus, we suggest that a 'just in case' approach would not be appropriate.

A final issue relates to asymmetries in regulatory treatment. Essentially this arises where the Regulator "claws back" all upside benefits but requires the firm to bear all downside risks. Given that the Regulator has limited opportunities to trigger a review during an access arrangement period, there are only two mechanisms by which claw-back might occur including:

- Through the X in the CPI-X adjustment mechanism being too high.
- In the case of risks where the upside risk occurs in one access arrangement period and the downside risk occurs in the next. In these circumstances the benefits associated with the upside risk may be returned to consumers while the firm is left to bear the downside risks in a subsequent access arrangement period.

However, if the Regulator allows a higher rate of return to compensate for claw-back for the reasons given above, then logically, the Regulator should engage in such claw-back. It is difficult to see how firms would benefit from this, unless they believe they will be able, at the point when gains are received, to effectively lobby to keep them. Consideration of regulatory risk and the possibility of claw-back emphasises the importance of the Regulator coming to sound decisions that ensure that firms will earn appropriate rates of return.

6.1.3 Bankability, Capital Market Adequacy and Hurdle Rates

Bankability, capital market adequacy and hurdle rates represent obstacles to a potential project (in any industry, not just in the gas pipeline industry) that occur prior to that project being presented to the market. If a gas pipeline were not bankable (for example), then it would never even be made available to investors in the stock market in order for them to judge its risk relative to other investments. The same is true of a project which does not meet the hurdle rates of any investors in the marketplace. Capital market adequacy is a slightly different issue, and suggests that a given capital market is of insufficient depth to be able to support a given investment project. This may be the case in a very small capital market, say in Africa, but does not appear to be reasonable for Australia.

Just because a given project is not bankable, cannot pass the hurdle rates of any private sector investors or is proposed in an inadequate capital market, does not mean it is not worthwhile to the community. Indeed, many infrastructure projects are of this nature. In such cases, there is a prima facie case for government support to ensure that the particular project does proceed and deliver benefits to the community.

However, as discussed in Chapter Three, the appropriate means of government support is not through access regulation, but rather through government involvement perhaps by way of industry policy. For this reason, bankability, capital market adequacy and hurdle rates are not issues which should influence the regulator's determination of beta.[54]

6.1.4 Demand Risk

Pipelines, like other infrastructure, typically have long life-spans and face the risk of uncertain future demand. This is especially the case where contracts are short-term. Essentially the issue is similar to the risk of asset stranding. Investors are, however, able to mitigate these risks through portfolio diversification, with the result that demand risk is diversifiable.

In addition, firms can mitigate the risk of a shortfall in demand by requiring users to enter into long-term contracts, requiring take-or-pay commitments and by adopting risk mitigating tariff design options such as requiring capacity reservation charges to be high by comparison to throughput charges.

As in the case of asset stranding, firms can also adopt some form of accelerated depreciation.

One view is that pipeline owners should be compensated with a higher rate of return for taking the risk that future demand will be insufficient in the long-term to recover the cost of the investment. However, there is also an upside prospect of demand expanding and additional customers seeking access to the pipeline.

6.1.5 Concentrated Customer Demand and Flow Through of Risk From Customers

Some gas pipelines in Australia service a single industry (such as mining) or a small number of industrial customers. This is especially the case in WA, where, in contrast to states such as Victoria, the proportion of residential customers is greater and the diversity of the customer base is more concentrated.

Some pipeline owners have suggested that the risks they face reflect those of their customers and that these risks should be compensated for by the value of beta in their rate of return being the same or similar to the value of beta of their customers.

Moreover, it is sometimes argued that when the number of customers is small (or concentrated in a few sectors of the economy), exogenous shocks to these customers have a disproportionate effect on the pipeline owner, compared to a

[54] As in Section 3.2of this report, the recent Supreme Court decision interpreting Section 2.24 of the Code may require the Regulator to consider these issues. However, again, whilst potentially correct in law, this makes for poor economic regulatory policy, and perhaps renders Section 2.24 appropriate for review.

pipeline servicing a more diverse market. Information obtained through industry consultation indicates that Alcoa, Worsley, Alinta and Western Power account for just under 80 percent of gas transport through the DBNGP and Parmelia Pipelines while small commercial and residential users account for only about six percent. Clearly, the gas industry in WA is characterised by a small number of large customers accounting for the majority of demand.

However, the risks associated with exposure to investments that service concentrated or specialised markets can be diversified. Portfolio investors can diversify such risks by holding assets in their portfolio that balance their exposure to such specialised risks. Davis (1999), in advice to SAIPAR, has thus suggested that concentrated customer demand is inappropriately classified as a non-diversifiable risk.

In addition, the downstream risks faced by customers of a pipeline do not directly translate into the risks faced by a pipeline owner servicing those customers, because the pipeline owner is able to mitigate such risks through take-or-pay contracts and other similar mechanisms.

Hence exposure to demand concentrated in specific downstream industries is considered diversifiable.

6.1.6 Greenfield Developments and Risk

Investment in greenfield pipeline developments involves making decisions on capacity including spare capacity for future demand growth. Being new developments there is no history to guide demand projections. Hence, greenfield pipeline developments may face a higher level of demand uncertainty with the possibility of asset stranding if design capacity exceeds requirements.

The greater uncertainty in greenfields projects combined with incentive based regulation which involves the setting of a reference tariff can increase the probability that the actual rate of return will be below the rate set by the regulator. Limiting returns in this way may limit the upside of infrastructure projects (the possibility of earning high returns if the project is very successful), without making allowance for the downside (projects which earn less than the market rate of return are only allowed their actual rate of return).

However, it is important to consider the nature of regulation in Australia. It is incentive based, not rate of return regulation. Rates of return are used only insofar as they form part of the calculation of the reference tariff. It is not clear that incentive based regulation or reference tariffs result in limits to upside returns. Consider a greenfield project where demand doubles, compared to projected demand over the course of the Access Period. The reference tariff is set, and hence the pipeline operator is able to keep all the additional returns from additional demand (effectively increasing the rate of return) until the next regulatory review. Actual returns are thus not limited. It is at the next regulatory review that the issue of upside versus downside risk becomes an issue, as the Regulator may seek to return to consumers some returns which it believes excessive, but which the pipeline operator believes merely reflect an appropriate reward for the risks it has taken in investing in the pipeline. As the ACCC suggests in its *Draft Greenfields Guideline for Natural Gas Transmission Pipelines* (ACCC, 2002d), these risks associated with greenfield investment are better dealt with through mechanisms such as longer Access Periods, or 'regulatory holidays', long enough that sufficient information becomes available to determine whether returns have been excessive, or whether they merely reflect risk.

The downside risk, that sufficient demand will not eventuate to earn a reasonable rate of return at the reference tariff offered by the regulator, is a different matter. An increase in the rate of return used in a regulatory decision has the effect of increasing the reference tariff, and in general terms, if demand does not eventuate at a lower price, it will not eventuate at a higher price. Thus, it is a fallacy to suggest that raising rates of return will result in more customers, or that existing customers will demand more. However, if the customers who do eventuate have inelastic demand, setting the reference tariff too low may result in a situation where the pipeline operator is unable to raise prices to these customers (who, with inelastic demand, will not decrease their demand substantially in the face of higher prices) to recover the cost of its investment. This is the constraint faced by pipeline operators in the form of downside risk.

A gas pipeline exhibits decreasing returns to scale, which means that average costs fall.[55] Thus, if reference tariffs are set at the point where the average cost curve cuts the lower limit of likely demand, then pipeline operators will always be able to make strictly positive returns on their investment. Consumers will lose some consumer surplus if demand is higher than the lower limit predicted, and there may be some deadweight losses, compared with the situation which would eventuate if future demand is certain. However, if a pipeline does not currently exist then net consumer welfare will always be increased by construction of the pipeline. This suggests a methodology for price setting for greenfield pipelines which removes downside risks for the pipeline operator, and is strictly welfare enhancing for consumers, and which, moreover, does not mean that pipeline owners will be able to reap monopoly profits, as they can if regulatory holidays are utilised.

[55] This is true at least across the range of output before new fixed investment is needed to satisfy new demand.

Rather than attempting to forecast demand precisely, the pipeline operator presents a forecast of likely demand (incorporating a lower limit) and a cost structure for the pipeline it wishes to build. The Regulator assesses both and sets the reference tariff for access equal to the point where average costs cut the lowest demand curve thus constructed.

The approach generates ordered pairs of intersections between the demand and average cost curves which are incentive compatible; if the pipeline owner cites lower limits of demand in the context of pipelines which are relatively large scale, the higher costs associated with building a larger pipeline may offset the potential benefits to be gained by estimating low demand and hence high reference tariffs, resulting in few net benefits to Greenfield pipeline developers from attempting to 'game' the regulator.

The approach also removes downside risks associated with pipeline construction; if greater demand does eventuate - the firm would simply earn higher returns for its investors. If higher than predicted demand does not eventuate, the firm still covers costs.[56] Consumers are worse off than they would have been had perfect demand forecasting been possible, but much better off than they would have been if the pipeline had not been constructed due to the Regulator setting a reference tariff too low for the pipeline operator to earn a commercial rate of return. In pushing for higher rates of return, pipeline operators are seeking a similar result, but this methodology is substantially more transparent and, because it addresses the underlying economic issue, is more likely to deliver the appropriate results than attempting to manipulate the situation with adjustments to the rate of return.

In its Central West Final Decision, the ACCC discusses two regulatory options to assist greenfield developments (ACCC, 2000a, pp26-41). The first relates to depreciation methodology and the second involves the lengthening of the access arrangement period which would allow pipeline owners additional time over which to retain the benefits of any efficiency improvements. The ACCC in its Guidelines on Greenfields Investment also suggests some other mechanisms such as: longer review periods (e.g. 10 years); accelerated depreciation; long-term contracts; retention of revenues associated with greater-than-anticipated demand; and tariff re-determinations in the event of less-than-anticipated demand. All these are compatible with the methodology described above.

[56] If demand transpires to be lower even than the lower limits of forecasts, the pipeline owner retains the right to renegotiate the access arrangement.

6.1.7 Input Cost Variation

If the inputs utilised by the pipeline owner in delivering services rise substantially in cost during the period of regulation, this may result in substantially lower net earnings unless cost increases can be passed on. Some stakeholders have suggested that risks associated with input cost variation should be reflected in beta.

However, general increases in the price level of inputs are passed on through the estimate provided by the service provider of future costs (including inflation). Moreover, a pipeline owner can, at any time, apply to the Regulator for a review of the Access Arrangement to account for any rise in costs.

Addressing the risk of input cost variation in beta or cash-flow compensates investors whether such variation occurs or not. Addressing it through CPI-X or through a review of an Access Arrangement ensures the issue is addressed only if it occurs. Hence, this is considered to be a more appropriate method of addressing the issue.

6.1.8 Sovereign and Political Risk

Sovereign or political risk refers to the risk that the controlling political entity in a State engages in some form of conduct that impacts on investment in the jurisdiction. In extreme cases, this could take the form of asset seizure. A less extreme example is a change in taxation laws. However, sovereign or political risk can also be in the form of an upside benefit. Sovereign risk is distinct from regulatory risk, as the Regulator has no control over it.

Since investors are generally able to diversify their portfolio across global jurisdictional boundaries, sovereign and political risk is generally diversifiable. This view is consistent with that by Davis & Handley (2002) who also classify it as non-systematic. In addition, sovereign risk will be reflected in the market risk premium and/or risk-free rate, and to incorporate it in beta would result in double counting.[57]

[57] This is true only to the extent that sovereign risk affects all sectors of the economy equally. For example, arbitrary seizures of assets is likely to affect the economy as a whole, but native title is likely to affect only those assets which have particular land holdings associated with them. However, in the case where sovereign risk affects different assets within a country differently, an investor can diversify the risk by purchasing assets in the relevant country not subject to the sovereign risks; in essence, this is the same as the means of addressing risks of investing in the gas industry (see below)

6.1.9 Global Economic Growth

Global economic growth is commonly cited as a systematic risk. Portfolio diversification will not reduce exposure to the risk of variations in global economic growth. Whilst it is possible to purchase futures contracts on the price movements of certain commodities, futures contracts based on the movement of the global economy as a whole are not known to be available.

Note, however, that national and global economic growth are different, in that it is possible for an investor to diversify away from volatility in the growth of a domestic economy by purchasing investments in another country, but it is not possible to diversify against volatility in global economic conditions. Hence, volatility in global economic growth is considered to be a systematic risk.

6.1.10 Innate Riskiness of Incentive Versus Rate of Return Regulation

Alexander, Mailer, & Weeds (1996) compare asset betas in US and UK utilities. In both countries, many utilities are publicly listed, and hence market-based betas are available. In the UK, incentive based regulation is used, whilst in the US (generally), rate of return regulation is used. The paper found that asset betas were higher in the UK compared to the US. Some stakeholders have argued that this provides support to the intuitive idea that incentive based regulation is inherently more risky than rate of return regulation. This is then used to suggest that adaptation of US asset betas into the Australian context should include some form of "incentive based regulation premium".

However, the Alexander et al state that such differences could be explained by a multitude of reasons, including different industry structures, different markets, different geographical conditions and different ownership structures. Moreover, they suggest that different constructs of market indices, and different weights of utility stocks within markets also affect beta. The authors in fact found little to suggest that incentive based regulation was the dominant factor for the higher observed asset betas.

In any event, investors are able to diversify against all forms of regulated investments, which would categorise the risks associated with both of these forms of regulation as non-systematic.

6.1.11 Option Risk

Some observers have suggested that investors, in considering committing to a large infrastructure investment such as a gas pipeline, assume a risk that may not be adequately reflected by beta on account of the non-reversible nature of the investment.

The difficulty with this is that from the point of view of a portfolio investor, an investment in a firm whose principal income earning asset is a non-reversible infrastructure asset is nonetheless a tradeable asset. Hence the investment is diversifiable and any risk associated with this investment is non-systematic.

6.1.12 Country Risk

In contrast to sovereign or political risk, some commentators have suggested that firms face unique risks by investing in Australia. Some of the perceived risks cited are a thin market and geographical isolation.

However, the general mechanism of the CAPM accounts for risks that pertain to an entire country through the risk free rate and/or the market risk premium, as NECG suggests in its comparison between Australia and the US and UK. To the extent that risks pertaining to a country as a whole are not reflected in the market risk premium, such risks would be non-systematic, as portfolio investors are free to trade in stocks internationally.

6.1.13 Risk of Investing in WA

Some commentators have suggested that the risk of investments in WA are comparatively more risky as compared with investments in other States, due to its thinner population and different industry mix with a heavier reliance on the resources sector. It has been suggested that beta should be adjusted upwards to reflect this.

Absent of evidence to the contrary, it is difficult to conceive of risks inherent in the Western Australian market which cannot be diversified by an investor through investments in other markets. Should these risks exist and affect the market as a whole (in a manner which prevents investors from diversifying through holding stocks in interstate or overseas companies), then this would be reflected in a higher risk-free rate and/or market risk premium for the WA market, as NECG argues is the case in comparing Australia with the UK and US.[58] To the extent that risks pertaining to WA are not reflected in the market risk premium, as indicated by market behaviour, such risks are non-systematic since portfolio

[58] Developing a market risk premium for the WA 'market' is difficult, as WA firms list on the ASX, and a distinct local market no longer exists. However, a rigorous analysis of the returns of firms domiciled in WA compared to nationally might form a useful addition to the regulatory debate in WA.

investors are free to diversify their portfolios and trade in stocks both nationally or worldwide.

6.1.14 Risk of Investment in the Gas Industry

Some commentators have suggested that the gas industry is "special" in that it is subject to unique risks requiring a higher rate of return to ensure adequate investment.

The methodology adopted by regulators in Australia and in other parts of the world has generally involved the use of a proxy beta, which takes into account the market indicated risk for the particular industry involved.

Essentially, the circumstances that apply to investment in the Western Australian gas industry are similar to those discussed under the section on the risk of investing in WA. Investors are not only free to diversify their portfolios across different States or counties they are also free to diversify across different types of industry. The market risk premium reflects variations in risks between different States or countries and beta reflects variations in risk between different types of industry. To the extent that risks pertaining to WA are not reflected in the risk premium and to the extent that risks pertaining to the type of industry are not reflected in beta, as indicated by market behaviour, such risks are diversifiable and are therefore non-systematic.

7 BIBLIOGRAPHY

Alexander I, Mailer C, & Weeds H, 1996, "Regulation Structure and Risk and Infrastructure Firms: An International Comparison", *World Bank Policy Research Working Paper no 1698*

Allen Consulting Group (ACG), 2002, "Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities", *Report for the Australian Competition and Consumer Commission,* July 2002

Australian Bureau of Statistics, 2001, *Summary of Industry Performance,* ABS Cat no 8140.0.55.002

Australian Competition and Consumer Commission (ACCC), 1998, *Final Decision: Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia(Assets) Pty Ltd for the Principal Transmission System, Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System, Access Arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, October 1998, Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Competition and Consumer Commission (ACCC), 1999, *Draft Statement of Principles for the Regulation of Transmission Revenues,* May 1999, Available from: http://www.accc.gov.au/electric/fs-elec.htm

Australian Competition and Consumer Commission (ACCC), 2000a, *Access Arrangement by AGL Pipelines (NSW) For the Central West Pipeline: Final Decision* June 2000. Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Competition and Consumer Commission (ACCC), 2000b, *NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04: Decision,* January 2000, Available from: http://www.accc.gov.au/electric/fs-elec.htm

Australian Competition and Consumer Commission (ACCC), 2001a, *Access Arrangement by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System: Final Decision* September 2001, Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Competition and Consumer Commission (ACCC), 2001b, *Access Arrangement by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline: Draft Decision,* May 2001, Available from: http://www.accc.gov.au/gas/fs-gas.htm.

Australian Competition and Consumer Commission (ACCC), 2002a, *Access Arrangement by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System Final Approval*, July 2002, Available from: http://www.accc.gov.au/gas/fs-gas.htm .

Australian Competition and Consumer Commission (ACCC), 2002b, *Submission to the COAG Energy Market Review,* May 2002, Available from: http://www.energymarketreview.org/submissions/government.htm.

Australian Competition and Consumer Commission (ACCC), 2002c, *Final Decision: GasNet Australia access arrangement revisions for the Principal Transmission System,* November 2002, Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Competition and Consumer Commission (ACCC), 2002d, *Draft Greenfields Guideline for Natural Gas Transmission Pipelines,* June 2002, Available from: http://www.accc.gov.au/gas/fs-gas.htm Australian Competition and Consumer Commission

(ACCC), 2002d, *Draft Greenfields Guideline for Natural Gas Transmission Pipelines*, June 2002, Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Competition and Consumer Commission (ACCC), 2002e, *Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline: Final Decision,* December 2002, Available from: http://www.accc.gov.au/gas/fs-gas.htm

Australian Infrastructure Report Card Alliance, 2002, *2001 Australian Infrastructure Report Card,* mimeo

Australian Pipeline Industry Association Incorporated (APIA), 1998, *Submission to the Review of the Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia(Assets) Pty Ltd for the Principal Transmission System, Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System, Access Arrangement by Victorian Energy Networks Corporation for the Principal Transmission System,* mimeo

Bubnys E, 1990, "Simulating and Forecasting Utility Stock Returns: Arbitrage Pricing Theory vs Capital Asset Pricing Model", *The Financial Review,* vol25 no1 pp1-23

Davis K, & Handley J, 2002, *Cost of Capital for Greenfields Investments in Pipelines,* Report prepared for the ACCC, April 2002.

Davis K, 1998, *The Weighted Average Cost of Capital for the Gas Industry*, Report prepared for the ACCC.

Davis K, 1999, *The Weighted Average Cost of Capital for Access Arrangements for Envestra*, Report prepared for SAIPAR.

Deitrich JK & Heckerman DH, 1983, “Determinants of the Systematic Risk of Electricity Utilities: Theory and Estimation”, *Applied Economics*, vol15 no5 pp619-33.

Devany M, 1991, “Regulator Selection and Endogenous Systematic Risk”, *Energy Economics,* vol13 no 2 pp 86-92.

Fama EF & French KR, 1992, “The Cross-Section of Expected Stock Returns”, *Journal of Finance* vol47 pp427-465

Fama EF & French KR, 1993, “Common Risk Factors in Returns on Stocks and Bonds”, *Journal of Financial Economics*, vol33 pp3-56

Fama EF & French KR, 1995, “Size and Book-to-Market Factors in Earnings and Returns”, *The Journal of Finance,* vol50 pp131-155

Fama EF & French KR, 1996, “Multifactor Explanations of Asset Pricing Anomalies”, *The Journal of Finance,* March no1 pp55-84

Fang H & Loo JCH, 1996, “Foreign Exchange Risks and Common Stock Returns: A Note on International Evidence”, *Journal of Business Finance and Accounting,* vol23 no3 pp473-80

Federal Energy Regulatory Commission (FERC), Various Years, *FERC Major Natural Gas Pipeline Annual Report Form 2,* Available from: http://www.ferc.fed.us/gas/form_2/fm2.htm

Fraser P & Buckland R, 2001, “Political and regulatory Risk: Beta Sensitivity in UK Electricity Distributors”, *Journal of Regulatory Economics,* vol19 no1 pp5-25.

Fuller R & Hickman K, 1991, "A Note on Estimating the Historical Risk Premium", *Financial Practice and Education,* vol1 no2 pp45-49

Gandolfi MT, Jenkinson T & Mayer C, 1996, *Regulation and the Cost of Capital,* Oxford School of Management Studies, mimeo

Green R & Rodriguez-Pardina M, 1999, *Resetting Price Controls for Privatised Utilities: A Manual for Regulators,* World Bank, Washington DC

Groenewold N & Fraser P, 1997, "Share Prices and Macroeconomic Factors", *Journal of Business Finance and Accounting,* vol24 no9&10 pp1367-83

Hathaway N & Officer R, 1995, *The Value of Imputation Tax Credits,* Finance Research Group, Melbourne Business School, Available from: http://www.mbs.unimelb.edu.au/staff/more/imptaxcredits.pdf

Independent Pricing and regulatory Tribunal of NSW (IPART), 1999a, *Access Arrangement for Great Southern Energy Gas Distribution Networks Ltd: Final Decision,* March 1999, Available from: http://www.ipart.nsw.gov.au/

Independent Pricing and regulatory Tribunal of NSW (IPART), 1999b, *Access Arrangement for the Albury Gas Company Ltd: Final Decision,* December 1999, Available from :http://www.ipart.nsw.gov.au/

Independent Pricing and regulatory Tribunal of NSW (IPART), 2000, *Access Arrangement for AGL Gas Networks Ltd Natural Gas System in NSW: Final Decision* July 2000, Available from http://www.ipart.nsw.gov.au/

International Energy Agency (IEA), 1998, *Natural Gas Distribution: Focus on Western Europe,* Available from: http://www.iea.org/pubs/studies/files/ngdist/#table

Ismail BE, Kim MK & Kirk FR, 1994, "Accounting Data and the Prediction of Risk in the Extremes*", Review of Financial Economics,* vol4 no1 pp55-68

James C, 2002, "Your Double-Digit Days Are Over", *Australian Financial Review,* 25th February 2002

Lally M, 2002, *"Determining the Risk-free Rate for Regulated Companies",* paper prepared for the Australian Competition and Consumer Commission

Lee CP, Chen KC & Lian KT, 1995, "Systematic Risk, Wage Rates and Facto Substitution" *Journal of Economics and Business,* vol47 no3 pp267-79

Lettau, M & Ludvigson, SW, 2001, "Resurrecting the CAPM: A Cross-Sectional Test When Risk Premia Are Time-Varying", *Journal of Political Economy*, vol109 no6, pp238-87.

Markowitz H. (1952) "Portfolio Selection", *Journal of Finance,* December

McCarthy J, 2002, "Gas Demand Estimates Just Hot Air", *Herald Sun,* 18th April 2002 p68

Meier I & Jagannathan R, 2002, "Do We Need CAPM for Capital Budgetting?" , *National Bureau of Economic Research Working Paper 8719,* January 2002 Available from: http://www.papers.nber.org/papers

Morana C & Sawkins J W, 2000, "Regulatory Uncertainty and the English and Welsh Water Industry and Periodic Price Review", *Journal of Regulatory Economics,* vol17 no1 pp87-100

National Economic Research Associates (NERA), 2001a, "International Comparison of Utilities' Regulated Post Tax Rates of Return In: North America, the UK, and Australia", March 2001

National Economic Research Associates (NERA), 2001b, "NERA response to NECG Report. 17 August 2001

National Economic Research Associates (NERA), 2002, *"Report for the National Audit Office on Regulatory Risk"*, in Pipes and Wires by The National Audit Office 10 April 2002

Netherlands Electricity regulatory Service (DTE), 2000, *Guidelines for Price Cap Regulation of the Dutch Electricity Sector: In the Period From 2002 to 2003*, February 2000, Available from: http://www.nma-dte.nl/en/?lang=en

Network Economics Consulting Group (NECG), 2001, *International Comparisons of Rates of Return: Comment on NERA Report,* 18th July 2001

Norton SW, 1985, "Regulation and Systematic Risk: The Case of Electricity Utilities", *Journal of Law and Economics,* vol28 no3 pp671-86.

Office of Gas Access Regulation WA (O*ff*GAR), 2000a, *Final Decision: Access Arrangement, Parmelia Pipeline*, October 2000, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of Gas Access Regulation WA (O*ff*GAR), 2000b, *Final Decision: Access Arrangement, Mid West and South West Gas Distribution Systems*, June 2000, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of Gas Access Regulation WA (O*ff*GAR), 2001a, *Final Decision and Final Approval: Access Arrangement, Tubridgi Pipeline System*, October 2001, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of Gas Access Regulation WA (O*ff*GAR), 2001b, *Draft Decision: Access Arrangement, Goldfields Gas Pipeline*, April 2001, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of Gas Access Regulation WA (O*ff*GAR), 2001c, *Draft Decision: Proposed Access Arrangement, Dampier to Bunbury Natural Gas Pipeline* August 2001, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of Gas Access Regulation WA (O*ff*GAR), 2003, *Final Decision: Proposed Access Arrangement, Dampier to Bunbury Natural Gas Pipeline* May 2003, Available from: http://www.offgar.wa.gov.au/main.cfm

Office of the Regulator General, Victoria (ORG), 1998, *Multinet Energy Pty Ltd, Mutlinet Assets Pty Ltd, Westar (Gas) Pty Ltd, Westar (Assets) Pty Ltd, Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd Access Arrangement: Final Approval,* December 1998, Available from: http://www.reggen.vic.gov.au/PDF/1998/gasfinap.pdf

Officer R, 1994, "The Cost of Capital Under an Imputation Tax System", *Accounting and Finance,* vol34 no1 pp1-18

Productivity Commission (2001), *Review of the National Access Regime: Inquiry Report,* 28, September 2001

Queensland Competition Authority (QCA), 2001, *Final Decision on Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Ltd and Envestra Ltd*, October 2001, Available from: http://www.qca.org.au

Riddick, LA, 1992, "The Effects of Regulation on Stochastic Systematic Risk", *Journal of Regulatory Economics,* vol4 no2 pp139-57

Rosenberg B & Guy J, 1976, "Predicting Betas From Investment Fundamentals", *Financial Analyst Journal,* May-June

Ross SA, 1976, "The Arbitrage Theory of Asset Pricing", *Journal of Economic Theory,* vol13, no3, pp341-60

Shiller RJ, 2003, *The New Financial Order: Risk in the 21st Century,* Princeton University Press, Princeton NJ

South Australian Independent Pricing and Access Regulator (SAIPAR), 2001, *Access Arrangement for Envestra Limited's South Australian Natural Gas Distribution System: Final Decision,* December 2001, Available from: http://www.saipar.sa.gov.au/

Sudarsanam PS, 1992 "Market and Industry Structure and the Corporate Cost of Capital", *Journal Of Industrial Economics*, vol40 no2 pp189-99

Thompson DJ, 1976, "Sources of Systematic Risk in Common Stocks", *Journal of Business*, vol49 no2 pp173-88

Wong KP, 1995, "Cournot Oligopoly and Systematic Risk", *Journal of Economics and Business,* vol47 pp385-95