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Report on

"Cost of Capital for Greenfields Investments in Pipelines"

Prepared for the ACCC by

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Executive Summary

Greenfields investments are new, large scale, projects which involve a number of specific risks. It is important that the regulatory framework for determination of access pricing does not create disincentives to such investment. This report identifies three key issues which need to be considered in applying the access pricing model, previously used primarily with reference to mature assets, to greenfields investments.

First, there are some grounds for believing that the systematic risk of a greenfields investment project, *in the absence of access regulation*, is somewhat larger than that for an established mature asset. This arises from the longer "duration" of expected cash inflows (reflecting time for growth of the market) and thus potentially greater sensitivity of the market value of the asset to changes in market wide required rates of return. It should be noted however, that the regulatory approach to access pricing, through loss carry forward provisions etc., may reduce this effect. In addition, foundation contracts with major customers mean that much of the systematic risk may be borne by that group (and reflected in the terms of such contracts). The net effect is difficult to determine, but may be accommodated by choosing a beta estimate in the upper half of the acceptable range derived from analysis of gas transmission businesses.

Second, there is no strong case for adjusting the cost of capital to allow for the range of specific risks which development of a greenfields project involves. Project finance techniques and financial engineering enable such risks to be efficiently passed to those most willing to bear them. It can be expected that costs of such risk shifting and sharing will be reflected in construction costs, operating and maintenance costs, or in explicit financing costs, and thus already find reflection in the regulatory access determination process. To also adjust the cost of capital for such specific risks would involve an element of double counting, and is not recommended.

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Third, disincentives for investment in such projects can be created if the regulatory approach does not recognize that investors can incur expenditures on projects which are not sufficiently successful to cause third party access regulation to be requested. Given a non-zero probability of inadequate returns in some circumstances, potential investors will require that greenfields projects have a positive probability of excess returns in circumstances where the project is successful. If access regulation is invoked only when a project is successful, and allows investors to achieve only the required rate of return in those cases, incentives to invest in projects which have a non-zero risk of failure will be damaged. For compatibility with private sector incentives, the regulatory approach needs to be based on reasonable forecasts and expectations of market conditions which were those applying at the time investment was first contemplated – not on forecasts which have altered due to the, post investment, acquisition of information. In this respect, the regulatory structure applied to new investment such as in greenfields projects need to be somewhat different from the approach used in setting access prices for existing assets which has been the major focus to date. One way in which this might be achieved is through commencement of the process of determining access arrangements at an early stage in the project feasibility stage, such that regulatory commitment based on information available at that date can be secured, and the risk of subsequent "expropriation of value" diminished. In order to eliminate any regulatory uncertainty at this point it would appear appropriate to have a regulatory determination either coincident with, or immediately prior to financial close for the project.

Introduction

This report considers the appropriate determination of the cost of capital for "greenfields" investments in gas transmission pipelines. Specific questions to be addressed at the request of the ACCC include:

1. Whether the CAPM is an appropriate framework for assessing the WACC facing a 'greenfields' pipeline.

2. How should risks that are specific to the project be recognised and compensated? For example, the level of return that may accrue to a 'greenfields' pipeline is more uncertain than the returns to a mature pipeline owing to variation in financial parameters during development and construction (such as exchange rates), construction cost variability, operating cost variability (including teething problems) and demand uncertainty (beyond foundation contracts).

3. Whether the CAPM should be augmented to account for the specific risks facing a 'greenfields' pipeline. Specifically, is it appropriate to inflate the beta, and if so, over what period should the inflated beta operate.

4. Whether it is appropriate to utilise a single beta for the pipeline industry as a whole, or whether separate betas should be developed for mature and 'greenfields' pipelines. Is there a case for separating cash flow streams (for example, foundation contracts and speculative demand) and applying different WACCs to each.

5. Subject to the views regarding 1 to 4 above, does a CAPM approach to determining WACC and compensating specific risks in cash flows provide adequate compensation for potential downside risks.

The report is structured as follows. First, section one outlines the major characteristics of the gas transmission industry and investment projects involving construction of a "greenfields" pipeline in order to identify the nature of risks and key determinants of an investment decision. This section also briefly considers features of financing and other contractual arrangements with users of the pipeline which are relevant. Section two then provides a brief overview of existing Australian regulatory arrangements for new gas pipelines. Section three considers whether there are specific "regulatory risks" which need to be considered. Section four examines the specific risks associated with greenfields investments and considers how they may be treated in the investment decision making process. Section five examines the applicability and use of the CAPM in determining the cost of capital for investment projects generally and greenfields investments specifically. Section six considers the specific question of determination of beta for greenfields investment projects relative to mature pipelines. Section seven examines how specific characteristics of greenfields investment projects should be incorporated into the regulatory approach to access pricing. Section eight summarizes and concludes.

Before proceeding, it is important to clarify the interpretation of "greenfields pipelines". In some usages, this term refers specifically to the case where a pipeline is to be constructed across land which has not previously been used for such a purpose, such that obtaining approvals for that purpose is a major aspect of the project. FERC (2001) note that in the USA the timelines in that process prior to filing an application for approval with FERC could involve as much as 12 months. In the Australian debate, the term "greenfields" appears to have been more generally used to refer to pipelines which are specific in terms of supplying a geographic region which has not previously had access to natural gas. This can be contrasted with existing "mature" pipelines such as those originally in public ownership serving developed markets, and which have been subsequently privatized. It can also be compared with new pipelines investment projects which involve connections between existing pipelines. In this report we adopt the definition of a "greenfields pipeline" as one which is a new investment project involving supply to a new market. This recognizes that obtaining land access rights is an important aspect of most such projects, but focuses particularly upon the non-existence of a prior market for output as the distinguishing characteristic.

1. Pipeline Investments in Australia – a brief overview

The gas transmission pipeline industry in Australia has almost doubled in scale over the past decade, such that there were around 17,000 km of pipelines in operation in 2001. More generally, interconnection of pipelines has been facilitated such that competition can now exist in provision of transmission services from supply sources to ultimate customers. Following deregulation in the 1990s, transmission pipelines are now operated by the private sector and transmission businesses have been "ring-fenced" from upstream and downstream activities. In particular, the transmission business must be a legal entity which does not carry on any related business activity, although the ownership structure of the entity may very likely lead to situations in which related parties are engaged in upstream or downstream businesses. Under the regulatory arrangements of the Gas Code, access to transmission services of existing pipelines is expected to be available on equal terms to all applicants. Box 1 provides a summary of relevant characteristics of the pipeline industry (see also Australian Gas Association, 1998, and Lawrey, 1998)

Box 1
Gas Pipeline Industry Characteristics

- Government ownership, operation, and network expansion has been replaced by private ownership and responsibility.
- The assets are long lived, and investment involves significant sunk costs
- Technological change in the transmission industry has been, and appears likely to be, relatively modest.
- Transmission costs are a relatively minor component of the total price of the final product (energy available at a specific location). Competition between alternative energy sources is relevant to, but not necessarily the major driver of, profitability of pipeline operations.
- "Ring fencing" provisions mean that while there may be ownership linkages, pipeline operations are unbundled from upstream or downstream interests;
- There are several companies operating in the industry which potentially might compete in the construction and development of new pipelines
- Transmission pipeline customers include large companies, electricity generators, and "aggregators" servicing the retail and commercial sector.
- The industry is regulated principally under the Gas Code
- The right to bypass current pipeline systems may discipline the pricing behaviour of pipeline companies, although inherent economies of scale in pipelines and the sunk costs involved in entry limit the effectiveness of such discipline.

On the basis of forecast growth in demand for natural gas, there is a significant potential for new pipeline construction, and a number of projects are under way or planned. However, various industry participants have argued that incentives for development of new pipelines are inadequate and hampered by the regulatory system in Australia. One concern relates to tax issues, particularly following the removal of accelerated depreciation arrangements:

> "Gas transmission pipeline developments are marginal, with negative cash flows in their early years as markets for gas develop and grow. This situation was offset, to a degree, by favourable taxation depreciation arrangements which applied from 1992 until September 1999 under so called "accelerated depreciation" which gave an effective tax life of around 8 years for pipeline developments. This was an important factor for pipeline development. Pipeline

> projects involve large up front capital expenditures. Accordingly, early positive cash flows are important in determining the overall rate of return on those projects. For pipeline projects, early cash flows are negative and depreciation allowances allowed, to a certain extent, companies to achieve this early positive cash flow, overcoming inadequate returns to investors during the early years of operation." (Beasley, 2001)

Whether competitive forces lead to concessionary company tax arrangements being passed onto customers rather than contributing to company profits is a moot point[1]. However, it is worth noting that under the "building block approach" adopted by access regulators in Australia the change in tax arrangements would not necessarily operate to the detriment of pipeline owners or customers. The regulatory approach is premised on investors having an expectation of achieving the required *post tax* rate of return over the life of a project (and that required rate of return is, arguably, unaffected by the package of tax changes). Consequently, target revenue would be adjusted to reflect the net outcome of the lower corporate tax rate and removal of accelerated depreciations, and it is not *a priori* obvious how much or what direction of effect would result.

More generally, there have been many expressions of concern about the impact of the third party access arrangements upon incentives to invest and the existence of "regulatory risk" (see, for example, Lewis, 2001). Some of these issues are taken up in subsequent sections.

Investment in the development of transmission pipelines is a major project involving a variety of risks, which are discussed in detail later in this report. Quite complex ownership structures may be involved, and financing and contractual arrangements negotiated with third parties can be quite complex[2].

These arrangements reflect both risk sharing/shifting arrangements as well as solutions to various agency problems which exist, and will be influenced by the regulatory and legal environment. For example, pipelines could be developed and owned by gas explorers and producers to ensure transportation to markets for their product, in conjunction with long term sales contracts of gas to retailers or users. Such sales contracts can have several effects. These include sharing risk associated with concerns over market viability, providing incentives for retailers to develop the market for gas supply and avoiding adverse bargaining circumstances post construction when there is inadequate competition in the retail market.

In recent years, the options available for, and relative efficacy of various approaches to, structuring ownership, financing and contractual arrangements for such major projects have changed – reflecting a number of influences. One is changes in the regulatory approach to gas markets, which have encouraged

[1] It perhaps should be noted that depreciation allowances could only lead to a positive cash flow in the situation outlined in the quote (where the pipeline is likely to be in a tax loss situation and unable to immediately use the tax shield) if the tax shield could be used to offset tax liabilities from other projects.

[2] Illustrative is the ownership structure of NTGas which is described in Attachment 2 of ACCC "Issues Paper - application for waiver of ring fencing obligations by NT Gas Pty Ltd" http://www.accc.gov.au/gas/ring_fence/Issues_paper.pdf

competition in various parts of the supply chain. A second is the restrictions imposed by regulation such as the "ring-fencing" requirements which necessitate that a pipeline operator be a separate legal entity with, essentially, no special arrangements with other participants in the industry which could inhibit competition. A third is the developments in financial engineering and project financing which have enabled financial structures and markets to be developed which provide better ways of overcoming risk and agency problems inherent in such projects. The following quote from the Australian Council for Infrastructure Development illustrates.

> "As discussed above, the private sector have a large range of forms of funding which it can use to procure projects.
> For example, it can call on bank debt, bonds, institutional and sponsor equity, retail equity, mezzanine instruments and financial derivatives both locally and internationally. This range of options allows the private sponsor to match the project's characteristics with those of the lenders and various borrowers.
> The risk preferences of individuals and firms differ. Some risk bearers will be very conservative and seek minimum risk, others will be prepared to accept risks in the expectation of receiving a greater reward. Partitioning the finance into tranches of debt, subordinated or mezzanine debt and equity (of relatively increasing risk) ensures that the project developer (and ultimately the consumer) does not pay any more than it has to in order to transfer risk to a third party.
> In recent years project finance has developed to a fine art. Firms are able to finance projects on a stand alone basis, without putting their other assets at risk. This allows greater amounts of debt to be used to fund projects with expected robust cashflow, leading to lower overall funding costs. Banks have even been prepared to sculpt debt service profiles, capitalizing interest payments on a loan when a project is in a start-up phase and clawing those payments back once the project is operating with a steady cashflow, several years later.
> Other financial instruments also allow private project developers to match project risks to appropriate risk bearers. For example, retailers of natural gas are sensitive to weather risk. They sell less gas for heating when it is warm.
> On the other hand icecream manufacturers increase their cashflow in warm weather. The financial markets have developed derivative products to allow organisations such as these to pool their risks and reduce the overall risk to both organisations. This leads to lower costs of risk bearing and ultimately to cheaper services for consumers". (AusCID, 2000)

More concrete evidence of the effects of such arrangements is given in Kleimeier and Megginson (2000) who compare the characteristics of syndicated loans for large scale project finance with those of other corporate loans. Even though such loans are typically non (or limited)-recourse (to project sponsors) they find that the cost of debt, measured by the spread over LIBOR for such loans (at around 130 basis points), is no larger than for other corporate syndicated loans – although arrangers fees are somewhat larger.

2. Access Pricing and Regulation of Pipelines

Regulation of gas transmission and distribution pipelines with natural monopoly characteristics is undertaken under the *Gas Code*. Operators of covered pipelines are required to specify, and have approved, access arrangements for third party access to transportation services. New pipelines may become "covered" through: regulatory decision following application by a third party; request by the operator for coverage; if the pipeline is constructed following a tender process approved by the regulator. Access arrangements provide, *inter alia*, information on services available, reference tariffs, terms and conditions, capacity management policy, trading rights, queuing policy.

In addition, Part IIIA of the TPA also provides for a legal regime to facilitate access to the services of certain facilities of national significance. Under Part IIIA, service providers can submit access undertakings to the ACCC specifying the terms on which access will be made available to third parties. Section 44ZZA of the TPA sets out the matters the ACCC must have regard to in deciding whether to accept an undertaking.

It is important to ensure that the regulatory framework applied to greenfields pipeline investments is both appropriate, and understood to be appropriate by potential investors. The existing regulatory approach to access pricing has been applied primarily to "mature" gas transmission operations, for which assets and markets were already in place. Essentially the approach involves a "building block" structure in which "target" revenue is derived as the amount necessary to cover operating and maintenance costs, an appropriate return on capital employed, and a return of capital over the life of the assets. Based on that target revenue stream and forecasts of demand, access tariffs are derived. Note that the adjustment mechanism specified for tariffs, should demand vary from that forecast, means that revenue generated may fall short of, or exceed, the target revenue stream – with obvious implications for the profitability of the operations. The precise specification of such adjustment mechanisms is determined with the objective of providing incentives for efficient management, use and development of the assets.

It is not immediately apparent that an identical approach to that outlined above is appropriate for "greenfields" ventures. Figure 1 provides a "prototype" of a simplified decision model to illustrate some of the issues involved in undertaking pipeline investments, and which helps in identifying the salient issues. Note that there are three stages indicated. Stage one involves assessment of potential projects for viability, including negotiations with various participants, to determine whether a project is viable or not. There is some positive probability that expenditures will be incurred but a decision made that the project is not viable. This stage could involve a time span of, say, one year. The second stage is the construction phase which could also involve a time span of around one year depending on the scale and complexity of the project. The third stage is the output stage, during which time the market and sales revenue is expected to increase till planned capacity output is reached at some future date. After the commencement of this stage, the pipeline may become "covered" under the access arrangements and determination of third party access tariffs required. It is important to note, however, that the coverage application / decision could occur during the first or second stage.

First, it must be noted that incentives for investment relate to expectations held at date 0 – the point at which decisions are made to assess the viability of various projects. Since some business development activities will not be carried through to fruition, it is necessary, for incentive reasons, that returns from those which are successful are adequate to offset the expenditure on appraisal/evaluation of projects which do not proceed. Note, however, that in a competitive environment, only costs equal to those of entities with efficient business development activities would be subsequently recouped. Moreover, the sums involved, given the maturity and technology of the industry, and market characteristics, are very small relative to construction costs of projects that go ahead. Hence, it can be anticipated that such costs would be quite minor, and easily accommodated by regulators choosing an outcome for target revenue in the upper region of a deemed acceptable range.

The preceding argument can be summarized in the language of capital budgeting as follows. Commencement of the evaluation phase would only occur if the expected future cash flows (allowing for the possibility that the evaluation phase leads to a recommendation not to proceed – and thus no future cash inflows) are adequate on a risk adjusted basis.

Thus, if incentives to assess potential investment projects are not to be diminished, expected future cash flows conditional on the project occurring will need to have a positive NPV to offset the expected unrecouped costs of non-recommended projects[3].

While at date 1 the project will still be implemented if the NPV=0, since development costs are "sunk" at that stage, the incentive issues relate to the decision at date 0 to commit resources to project assessment.

It is thus important that the regulatory approach, although not having an actual effect until after date 2, ensure that the decision making at date 0 and date 1 is unbiased. Thus at date 0, the investment criterion would be that at date 1, the NPV of inflows (from date 2 onwards) minus the NPV of outflows (between dates 1 and 2) would be sufficiently positive to offset expected development costs of "failed investigations" of an efficient business developer. Thus a regulatory determination at date 2 would need to provide an adequate return on the cumulated costs of the project plus some allowance for failed investigations to ensure adequate incentives.

Another potential concern is that regulatory determinations may be made at a time at which further information about market conditions has become available, such that forecast demand on which those determinations are based is different to the expected demand underlying the original (date 0 and 1) investment decisions. If the regulatory system provides potential access seekers with a free option to obtain services when the market is found to be strong, at a price based on that discovery,

[3] Without reliable information on the project evaluation process, it is difficult to quantify such an effect. However, to illustrate, suppose that a project of $500m scale eventuates after preliminary analysis of five other discarded projects which each involved a cost of $50,000 - $100,000 (approximately one person year of time). The effect is an increase in total cost of 0.05% - 0.10% relative to the cost base of the project of $500m. Any adjustment to the required rate of return for the project to reflect this effect would be of a similar small magnitude (perhaps 5 – 10 basis points).

but not participate when the market is weak, the service provider is subject to an ex post cost which will deter investment. Specifically, for investment decisions at date 0 and 1 to be unaffected by subsequent regulatory determinations, the target revenue will need to be based on expected demand as forecast at date 0 (or 1). Should an access determination be required at some stage after date 2, because the market demand is high and the project successful, it would be inappropriate to base the regulatory access price on a forecast demand which has been updated as at that date. The appropriate forecast volume is the one averaging (with appropriate weights) both a successful outcome (which has occurred) with a lack of success (which has not eventuated). While this will leave the service provider earning *ex post* abnormal returns when the project is successful, that is necessary to ensure that *ex ante* (when success was not guaranteed) the project was one which had expected normal returns.

Note that practical implementation of such an approach is difficult, and could be mitigated by ensuring that regulatory commitment is achieved earlier in the development process. If coverage of a proposed pipeline, and a regulatory determination applicable for some adequate horizon, can occur at some point such as date 1, these problems may be diminished. It would thus seem appropriate to develop a process whereby the position regarding access arrangements is determined at an early stage in the project evaluation/ development process, such as at the time of financial close for the project.

Such an approach would not overcome all complications. For example, project developers may have real options which enable them to defer sunk costs and cope with uncertainty of future demand. For example, there is some flexibility in construction of a pipeline to allow for subsequent addition of extra capacity through the installation of additional compressors if demand is high. Since capacity can be increased by as much as 100 per cent by this process, this real option may possess significant value. Likewise, it may be possible to stage the development of a pipeline, first to one market and then conditional on realized demand, to a second market – giving another real option to expand.

3. Regulatory Risks

Regulatory risks are naturally of concern for potential investors in new pipeline projects, and may impact upon incentives for construction of new pipelines. However, it is useful to distinguish conceptually between three quite different (albeit potentially intertwined) types of effect which regulation might have on incentives for new pipelines investment.

The first type of effect is where there is no uncertainty about future regulatory actions, but where the effect of regulation is to prevent investors earning an adequate rate of return on their investment for the risk involved. Price controls such as old fashioned *rent controls* in the housing market, which restrict the price of output below a market equilibrium level, are an example. While this has the effect of inhibiting investment, and should not be a feature of the regulatory structure, it should not be viewed as regulatory risk since there is no uncertainty about the future arising from regulation or regulatory actions.

The second type of effect is where the regulatory structure alters the underlying risk of the project in such a way as to make the project unviable. Uncertainty about the security of property rights is one example. Legislation which provides some third party with an option to expropriate at some future time (some part of) the value of the project without adequate compensation to the original investors is another example. This is the type of effect described in King (2001) as potentially arising from the *ex post* declaration process involved in Part IIIA of the Trade Practices Act 1974. We discuss the relevance of this argument to the case of pipelines subsequently, but note here that it involves an asymmetric (downside) risk – unlike the third type of effect to be described below.

The third type of effect is where the future actions of regulators are not predictable, so that an additional source of uncertainty about future cash flows is introduced. For example, access prices may be regularly reset by regulatory decisions at future dates during the life of the project. The possibility that the approach adopted by the regulators in future decisions might change, or that decisions are not predictably related to market variables, creates an additional source of uncertainty. The risk arising here is "two-sided" since it is possible that future regulatory decisions could be either value creating or value destroying for the investors in the project. Since this type of risk has generated significant discussion, we believe it appropriate to spend some time examining several relevant issues.

Changes in the Structure of the Regulatory Model

Since the introduction of access pricing arrangements, there have been several changes in the way the regulatory model has been presented to illustrate the derivation of access prices. These changes have been NPV equivalent in effect and designed to enhance the transparency of the regulatory determination process. Others might occur in the future. Actual and potential (although not anticipated) changes, in the "framing" of the approach, but not in its substance or implications, include such things as:

- Adoption of a post-tax nominal returns framework rather than a pre-tax real returns framework
- Use of an equity rather than entity framework (ie a focus on returns to equity rather than a WACC)
- Use of the actual pattern of tax cash flows in the modeling process rather than cash flows implied by effective or statutory tax rates
- Changes in the regulatory depreciation schedules adopted.

In principle, changes such as those described above have no implications for the returns to investors in a project, provided that the correct parameters are used in the regulatory framework.[4] It is relatively easy to demonstrate, for example, that a post tax nominal returns to equity approach is identical to a pre tax real WACC approach. All variants of the model are based upon the same foundation of deriving a revenue stream which covers operating costs, and provides required returns to

[4] All the frameworks considered have the objective of providing the investor with a return on equity after tax commensurate with the requirements of financial markets (as indicated by CAPM). Therefore the revenues so determined must be equivalent, noting potential timing differences in actual cash flows.

investors, and return of capital invested over the life of the project, and are thus conceptually equivalent. In practice, however, changes in the presentation of the model have also been associated by participants with changes in the model parameters used by the regulators.

In summary, changes in the way the regulatory model has been presented, such as those described above which maintain the underlying building block approach (and are simply changes in the way in which the approach is presented or "framed"), do not impose risk upon investors in projects.

Changes in Parameter values chosen by Regulators

Implementation of the "building block" approach to setting of access prices requires regulators to decide upon specific values for key parameters of the model. These include such things as: systematic risk (beta), market risk premium, debt risk premium, appropriate capital structure, value of imputation credits. Ultimately judgement calls must be made regarding appropriate values of such parameters which are implicit in financial market prices but which are, generally, not directly observable. The objective of regulators is (or should be) to make decisions about such parameters which are unbiased estimates of the unobserved values implicit in current financial market prices.

Regulatory choices for such parameters could change over time for two reasons. The first is that it is recognized, with the benefit of hindsight and accumulation of evidence, that previous values chosen were not appropriate. The second is that the underlying, unobserved, parameter values can themselves change over time.

While the possibility of either of these types of changes occurring could be regarded as giving rise to regulatory risk, it should be noted that, in principle, such risk is symmetric (ie has both upside and downside) and, from the perspective of ultimate investors, largely diversifiable. Hence, there would seem to be few grounds for "pricing" of such risk in the determination of allowable revenues[5].

A further source of changes in parameter values arises from the existence of a regulatory horizon (typically five years) at which time access prices are recalculated based on contemporaneous market conditions. For example, the risk free interest rate used in calculating the required rate of return is set to its current value at the start of each regulatory review period. Even though the assets may be long-lived (20-50 years), regulatory practice to date has been to use a medium term risk free interest rate (such as a five year rate). Compared to a situation in which access prices were determined over a longer regulatory horizon using the required rate of return at the start of the period, such an approach may have the effect of reducing the systematic risk of the asset. The reason is that investor returns over any period include both cash flow (dividend) and price (capital value) change. Where cash flows are not readjusted frequently, changes in market determined discount rates will affect the market price of the asset and thus realized returns. If,

[5] Here however, we note that an industry perception (or stance) appears to exist that access regulators have an objective function which is biased towards consumers. In this respect it is unfortunate that there appears to be some unwarranted association of the "consumer watchdog" role of the ACCC with the distinct "umpiring" role associated with access pricing.

in the extreme case, cash flows are adjusted continuously in line with required rates of return, there will be no change in the market price of the asset. Realized returns will covary in line with market determined required returns (through the cash flow effect) but to a lesser extent than in the case where the market price of the asset is changing. In effect, some part of the systematic risk is being passed onto customers. Likewise, annual adjustment of target revenues and thus tariffs in response to realized inflation (where it differs from that forecast at the start of a five year regulatory review period) transfers inflation risks away from the supplier. Similarly, ability to request a regulatory reset review prior to the horizon date in the event, for example, of significant cost structure changes may also affect the extent of risk bearing.

Mispriced Third Party Access Options

It has been suggested (King, 2001) that the potential for declaration and regulatory determination of third party access prices can lead to disincentives to invest if the risk of project failure prior to that date is not incorporated into the regulatory determination process. This argument can be thought of in the context of option analysis as the regulatory system providing a third party (potential access seeker) with a free option to purchase services at a strike price below the true value of the service provision. The import of this argument is that, if disincentives to investment are to be avoided, the regulatory determination needs to take into account the uncertainty existing at the time the project was initiated and not be based on information which has emerged since and resolved some of the uncertainty.

To elaborate, consider the following example in which a risk neutral investor is contemplating an outlay of $1000 at date 0 which will create capacity to deliver a service in perpetuity starting at date 1. There are equal probabilities (of 0.5) that demand for the service will be 50 in perpetuity or 100 in perpetuity. The risk free discount rate is 10% p.a.. The investor is able to enter a foundation contract with a third party to sell services of 50 in perpetuity at a price of 1.2 per unit.

For the investor at date 0, the Net Present Value of the project (absent regulation) is given by:

$$NPV = -1000 + (50 \times 1.2)/(.10) + 0.5 \times (50 x\, p)/(.10)$$

where p is the price which can be charged for the spare capacity of 50 if demand turns out to be high. (The second term on the RHS is the present value of the perpetuity of guaranteed sales and the third term is the present value of the perpetuity of additional sales multiplied by the probability of that occurring). In this case the price p which make NPV = 0 and is thus the minimum to induce investment is:

$$p = (100 – 60)/25 = 1.6$$

Suppose, however, that if demand is high, a third party seeks access and the regulator determines the access price based on the knowledge that demand will be

100 in perpetuity. Denoting the regulatory access price as p_r the regulator will derive p_r from[6]:

$$NPV = -1000 + 100x\ p_r /(.10) = 0$$

which yields:

$$p_r = 110/100 = 1.0$$

It can be seen that while, ex post, this leads to a zero NPV conditional upon demand being high, the regulatory price is too low to ensure a zero NPV at date 0 unconditional upon (uncertain) future demand – which is required if investment is to be undertaken at date 0.

This example demonstrates a fundamental point regarding situations where regulators may be required to determine third party access prices at some date after an investment has been made. Access might only be sought in situations where uncertainty about market demand and the value of the service has been resolved after the investment was made. Regulatory determinations which are based on this new information about market demand will involve setting prices which are incompatible with appropriate investment incentives. While access prices which yield a zero NPV conditional on demand being high (and access being sought) will not cause the service operator to cease activity, expectations (or knowledge) that a regulator will act in this way is likely to act as a disincentive to undertaking investment.

As we have outlined earlier, in section 2, one approach to ameliorate this potential problem, is to ensure that the coverage and access arrangement decisions are made earlier in the development process. In effect, the time to expiry of the option to seek declaration and potential expropriation of value is dramatically reduced, thereby reducing the option's value. This appears to be a viable alternative to simply abolishing the option – as is implied by the suggestion which has been made to allow "access holidays".

4. Specific Risks of Pipeline Investments and their Management

Fundamentally, the risk of a project refers to the amount of variability in the underlying cashflows of the project and hence the variability in the rate of return on an investment in the project. The risk of a particular project is largely determined by the nature and specific business characteristics of the project. There is no standard system of classifying or defining project risks in general let alone classifying the risks specific to a gas pipeline project. However, the Productivity Commission has recently suggested the following useful classification of the major risks commonly associated with an investment in essential infrastructure facilities:[7]

[6] In this example, we assume that the access price is set without distinguishing between foundation contracts and other customers. Alternatively, the regulator might calculate the access price assuming that 50 units are sold at the foundation contract price and calculate p_r from: $NPV = -1000 +(50x1.2)/.1 +(50 \times p_r)/.1$, giving $p_r = 0.80$. The effect, in terms of incentives, is the same.

[7] Productivity Commission (2001 p.58).

Type of Risk	*Generic Description*
Market Risk	associated with changes in broad market parameters and economy wide conditions
Demand Risk	arising from uncertainty about the future demand and prices obtainable for the services of the facility
Network Risk	if the facility is part of a wider network, the demand risk may depend partly on the behaviour of the other network operators
Construction Risk	associated with unforeseen delays and costs during the construction phase
Technological Risk	reflecting uncertainty about how an untried technology will perform or the possible emergence of a superior competing technology
Sovereign or Regulatory Risk	arising from the possibility of government actions which will alter the viability of the project

The extent to which each of these risks relates to a particular gas pipeline project is likely to vary from case to case. Risk management plays an important role in infrastructure investments. A common objective is to allocate/shift specific project risks from the project sponsor to those parties who are best able to appraise and control them.[8] Traditionally, this has been achieved by way of complex contractual arrangements between the project sponsor and various key parties to the project including construction contractors, suppliers and customers. In relation to gas pipeline infrastructure, foundation contracts between the pipeline owners and upstream gas producers and downstream gas users has allowed project sponsors to deal with the critical aspects of demand risk and certainty of gas supply prior to the commitment of large amounts of capital to the project. Ultimately, the effectiveness of any contractual arrangement in mitigating risk to the owners will depend upon the nature of the contract, its specific terms and conditions and the creditworthiness of the other party. Other risk management techniques are also available including hedging and the recently emerging trend of "targeted risk coverage", which essentially aims to shift a particular risk from project sponsors to third party insurers.[9]

Whilst it is important to identify all the risks associated with a gas pipeline project it should be recognised that not all of these risks will then be relevent in determining the appropriate rate of return on the project. In particular:

(i) unlike investors in a mature pipeline, investors in a "greenfields" pipeline are, by nature of the project, exposed to the risks that exist not only at the operating/output stage but also to the risks that exist at the development and construction stages;[10]

8 See for example Brealey, Cooper and Habib (1996), and Esty (1999).

9 See for example Smith and Chew (2001) and Alderdice, Horwich and Feldman (2001).

10 For example, in its submission to the Productivity Commission review of the National Access Regime, the Chamber of Commerce & Industry of Western Australia asserts: "The risk entailed in purchasing (say) an established privatised asset is less than that in investing in a new asset. The market size and demand are known, prices are transparent, the technology and efficiency of the production processes are proven and the purchasers can be (reasonably) sure that the final cost of obtaining the asset is the price they agreed to pay. Unless rates of return reflect these different degrees of risk - or, a much less desirable outcome, the asset owner is able to shift some of

(ii) notwithstanding (i), it is well established in the finance literature that the appropriate measure of risk for determining the rate of return on a project (whether "greenfields" or mature) is the systematic risk of a project and not its total risk;[11]

(iii) the regulations currently appear to mitigate the impact of potential adverse construction risks associated with new pipelines by specifying that the capital base reflect the actual cost of construction (section 8.12 of the Gas Code); and

(iv) risk is an ex-ante concept which exists when there is uncertainty about *future* events which may effect the project. It is therefore logically inconsistent to assess the risk at some prior point in time using information known at a later point in time.

One additional issue to be recognized is that in large scale project financing, an assumption of a constant capital structure over time is unlikely to be appropriate. Financial arrangements will have been structured which involve changes over time in the mix of debt, equity and hybrid forms of financing. In estimating the cost of equity or a WACC, attention needs to be paid to the likely change in capital structure as the project progresses through its lifecycle.

5. The CAPM and required rates of return

The CAPM is typically used by firms to estimate the cost of equity capital as is shown in three recent surveys of corporate practice (Bruner, Eades, Harris, and Higgins, 1998, Gitman and Vandenberg, 2000, Graham and Harvey, 2001). Graham and Harvey find that some three-quarters of respondents to their survey use the CAPM (sometimes using a multi-beta approach incorporating other risk factors), as did eighty five percent of the best-practice firms in Bruner et al's sample and sixty five percent in Gitman and Vandenberg. Other approaches sometimes used include the dividend discount model (Cornell, Hirshliefer and James (1997) provide an overview of alternative approaches). Significantly, Graham and Harvey find that NPV or IRR techniques using the estimated cost of capital are always used by around 75 per cent of chief financial officers in their sample. (Bruner et al find that 89 per cent of their sample use some form of discounted cash flow approach).

There are seven principal alternatives to the capital asset pricing model that might be used to estimate a company's cost of equity capital (and thus its WACC):

- comparable earnings;
- discounted cashflow;

the risk - than a rate of return which might seem adequate or even generous for the purchaser of a privatised asset might not be enough to induce additional investment in the industry" (p. 14).

[11] The total risk of a project can be partitioned into two components; systematic risk and unsystematic risk. Systematic risk is due to factors which effect the economy as a whole while unsystematic risk is due to factors which effect only the project under consideration. Unsystematic risk can be eliminated by diversification. Within the CAPM framework investors are assumed to hold well diversified portfolios and therefore to have eliminated any unsystematic risk. In this case the cost of capital (required rate of return) on a project is determined by its systematic risk being the only risk that remains.

- price earnings ratios;
- risk premium;
- arbitrage pricing theory;
- the Fama-French model;
- the residual income model.

(see Davis and Handley, 1998) for more details regarding the first six approaches and Gebhardt, Lee and Bhaskaran, 2001 for a discussion of the last).

At this time, however, none of the alternative approaches have surpassed the CAPM in popularity or use in practice.

Use of the CAPM in project evaluation requires an estimate of the beta of the project. Often this is assumed to be equal to the beta of the company undertaking the project, but this is only appropriate if the systematic risk of the project and company are equal.

An estimate of a company's beta can be derived from the observed historical relationship between returns on the stock and the market, where this is available, or can be approximated by reference to equity betas of comparable companies. (Here comparable refers to companies engaged in similar business activities and thus likely to have similar underlying systematic risk). That approximation needs to allow for possible differences in leverage between the comparator companies and the company under consideration. Where the comparator companies are from a different country, the approximation will be less precise because of differences between the relevant market portfolios (against which covariances are being measured) and tax differences.

An alternative approach that is sometimes used is to examine the economic and financial fundamentals of the company or project. This involves analysing such characteristics as operating leverage and costs, product demand etc., to assess the extent to which returns on that activity will covary with overall economic activity. A difficulty with such an approach is that theory provides little guidance on the appropriate method for converting such information into an estimate of an "asset beta". One practical problem concerns the fact that the "beta" to be calculated relates to the covariance of the rate of return on the activity with the rate of return on some aggregate of risky assets, typically proxied by the equity market – even though that is not the true population of risky assets.

A more fundamental problem arises from the fact that the rate of return on a project / asset over any period of time reflects two factors. This is easily seen in the context of a listed stock, where the return ($r_{t,t+1}$) over the period t to t+1 can be written as:

$$r_{t,,t+1} = (P_{t+1} + D_{t+1})/P_t$$

where P_t (P_{t+1}) is the price at t (t+1) and D_{t+1} is the dividend (cash flow) between t and t+1.

Covariance of this return with the return on the market could arise because of covariance of the cash flow component or because of covariance of the price component with the return on the market. Generally, because of the stability of dividends over time, most of the covariance observed is due to the covariance of the stock price with the market index. Since both individual stock prices and the market index are present values of the relevant expected future cash flows, covariance can arise from either covariance in expected future cash flows or from covariance in the discount rate used to derive the present values. If changes in discount rates have any systematic component (such that changes in the discount rates (required rates of return) for the asset and for the market as a whole are correlated) this will affect the beta of the asset.[12] As Cornell (1999) demonstrates, this suggests that betas may be related to the duration of the cash flows of a project, with longer duration projects having *cet par* higher betas.

We consider the relevance of these arguments to the case of greenfields pipelines in the next section to suggest that relative to mature assets, where betas may be derived from using market data or the "comparables" approach, the beta for a greenfields project may be slightly higher. However, given the nature of the regulatory regime, and in the absence of evidence to the contrary, we do not expect that the difference involved is of such a degree as to suggest other than selection of a beta in the upper half of the range of reasonable values for the industry.

6. The systematic risk of "greenfields" pipelines

Do "greenfields" pipelines have different systematic risk to mature pipelines? We consider first the situation in the absence of regulation.

There is little doubt that, at the planning and construction stage which is relevant to incentives to invest, greenfields projects involve greater total risk. This reflects simply the greater uncertainty about future market demand relative to the case of a pipeline serving a mature market, as well as the additional risks involved in construction and development.

It is, however, far from apparent that this greater total risk translates into a difference in systematic risk. Although returns to investors in such a project may be more uncertain, some part of this risk can be avoided at zero cost by investors holding a diversified portfolio of investments, and thus does not require compensation by way of a higher expected (required) rate of return. The critical issue is the degree to which the return covaries with the overall return on the market portfolio of risky assets (and/or with any other identifiable risk factors which affect asset returns).

To the extent that a greenfields project involves servicing a particular geographic market, it could be argued that the systematic risk may be either greater or less than for a mature pipeline serving a broader market. Underlying this argument is the possibility that market demand, and thus cash flows, in the specific geographic market may have a different correlation with aggregate market conditions than in the case of the broader market. But without specific information on the market in question, there is no reason to presume an *a priori* difference on this ground.

[12] See Campbell and Mei (1993).

A more relevant cause of difference may be found in the *duration* of the expected cash flows of the project. An existing pipeline serving a mature market can be expected to have a demand pattern such that the cash flow stream arising over the remaining life of the pipeline looks somewhat like a "variable annuity"[13]. For a greenfields pipeline where demand will be initially low and increasing to capacity over time as the market develops, the cash flow pattern will look more like a (variable) growing annuity. On average, the cash flows to be received are more distant.

How might this affect the systematic risk? The answer may be seen by noting that the return to investors in an asset over any period consists of current period cash flow (dividend) plus capital gain (change in market value) over the period. Assuming, for the moment, that the cash flow components are constant, changes in market value arising from changes in market risk or time preferences and thus discount rates will be larger for the asset with longer duration of cash flows. Thus, market wide changes in risk or time preference will affect both overall market wide returns and returns on these assets, with a higher covariance between returns on long duration assets and the market than for short duration assets and the market.

The previous argument, which suggests that, *absent regulation,* greenfields pipelines may have a higher systematic risk is, however, only part of the story. Changes in market values may also arise from changes in expected future cash flows. There appears to be no *a priori* reason to believe that the covariance of expected future market wide cash flows with those of greenfields and mature pipelines will differ. However, contractual differences – such as the existence of long term contracts – could generate differences, perhaps smoothing cash flows and reducing systematic risk. Perhaps more significantly, it should be noted that the access pricing approach may act to reduce systematic risk of pipelines. Access prices and cash flows are regularly readjusted at the start of each review period to reflect movements in the level of interest rates. Consequently, the "market value" effect of changes in market wide discount rates arising from changes in the level of interest rates will be dampened – since expected future cash flows will be similarly affected. (Were the regulatory agency able to adjust the market risk premium applied in its decisions to exactly reflect changes in the (unobservable) true market risk premium, a similar dampening effect would arise for this source of market value changes).

In summary, there are some grounds for believing that the systematic risk of a greenfields pipeline may be somewhat higher than that for an existing mature pipeline, although the existence of long term contracts and the regulatory "reset" mechanism suggest that the difference may not be particularly large. We would expect that this could be accommodated by use of a beta estimate for Greenfield pipelines above the midpoint of the range of estimates for mature pipeline companies, but within the generally agreed reasonable range for such companies.

[13] We use this term to depict an uncertain future stream of cash flows which has a constant expected value per period.

7. Access pricing and specific risks of “greenfields” projects

Should “foundation” contracts be treated separately in the approach to access pricing for greenfields pipelines? In principle, it is possible to use an Adjusted Present Value type technique to determine the NPV of *any* project by partitioning the cashflows of the project into two or more separate and distinguishable components and then discounting each component at an appropriate risk adjusted rate. In the case of a greenfields pipeline project, a natural partition would be to treat the cashflows generated under foundation contracts differently to uncontracted cashflows. The discount rate to be applied to each cashflow stream will be determined by the systematic risk of those cashflows which in turn is determined by the level of total market demand and the precise nature of the foundation contract. Foundation contracts can take a variety of forms and may be used to hedge price risk and or quantity risk although clearly these risks are not independent. In addition, the foundation contract may include a capacity provision whereby a third party guarantees some minimum level of throughput. In certain cases it is possible to regard the foundation contract as a form of levered financing of the project, while it others it may be more appropriate to view it as equivalent to a form of equity interest. The particular case will determine the nature of the adjustment to make in calculating the systematic risk and required rate of return for the non-contracted cash flows.

To illustrate the issues, but not meant as an illustration of any specific case of foundation contract consider the following simplified example. A developer is considering investment in a transportation service (e.g. a pipeline) which will enable a raw material to be transported to service demand in a particular geographic market. For simplicity, assume that the life of the service and the market is one period only. Construction (and cash outflows) occur at date t = 0, and spot market sales of transportation services occur at date t = 1. Demand to be serviced at date t=1 is for a “delivered item” comprising the bundle of one unit of each of the raw material and transportation service. The transportation service has a capacity of 100 units, and demand for the delivered item is uncertain. In particular, we assume (very simplistically) that demand is price inelastic (at least with respect to the cost of transportation services) and take values between 100 and 0. (We examine below cases where demand is 0, 60 and 100). The delivered item is sold to consumers by retailers who purchase transportation services and the raw material. Retailer A has entered a foundation contract with the developer/operator to purchase 50 units (half the capacity) of the transportation service for a fixed price F (which we assume for simplicity is paid at date t=0). Other retailers (here denoted by retailer B) will purchase transportation services in the spot market at date t=1.

Under this simple structure, we note that the impact of the foundation contract upon the developer’s cash flows depend upon the characteristics of the market for the delivered item. Consider the following examples of demand conditions. If demand is 100, Retailer A uses the 50 units and retailer(s) B purchase 50 units in the spot market. If demand is 0, there is no spot market demand (and A has paid for 50 units of unused capacity). If demand is 60, there are many possible outcomes, of which we examine two. In case 1, the 60 units of demand are expected to split evenly between A and B, such that 30 units of transportation services are purchased in the spot market (and A has paid for 20 units of unused capacity). In case 2, demand orders are expected to flow first to A until 50 is reached and then to B, such that B purchases 10 units of transportation services in the spot market.

Note the following. In case 1, retailer A has effectively purchased half of the project, ie taken an equity interest by outlaying F at date t = 0. The systematic risk of the uncertain future cash flows to the developer is unchanged. Thus, it would be possible to value the project to the developer by discounting the uncertain future cash flows from spot market contracts at a discount rate appropriate to the project as a whole, and adding this to the fixed amount being derived from the foundation contracts. In case 2 however, the systematic risk of the cash flows to be received by the developer is altered by the effect which the sequencing of demand has on the distribution of cash flows. The developer will only receive cash flows equal to the excess of market demand over 50, and nothing if demand is less than 50. This means that the systematic risk of future cash flows is changed in much the same way as if the project had been levered (when creditors have first claim on aggregate cash flows up to some amount). Thus valuation of the project would involve discounting expected risky cash flows (which differ from those in case 1) at a discount rate which reflects the "leverage" effect and adding this to the fixed amount to be derived from foundation contracts. Note also that the fixed amount paid under foundation contracts could be expected to vary depending upon which of case 1 or 2 was perceived to be more likely. Appendix A provides an algebraic demonstration of these examples.

While there is some appeal in disaggregating cash flows between foundation contracts and other receipts, this would require a case by case analysis of the nature of the contracts and market characteristics. In addition, it is possible that foundation contracts written between related parties might involve risk shifting on terms different to those which would occur in market based transactions. Consequently, we are of the view that while such disaggregated analysis might provide a useful check on results derived using the WACC for total cash flows, the extra complications introduced make it unsuitable as a primary technique. However, if adequate information about the terms and nature of foundation contracts and market characteristics can be obtained, it could be a viable alternative.

8. Conclusion

Based on the preceding analysis, our assessment of the appropriate responses to the questions posed at the start of this report are as follows.

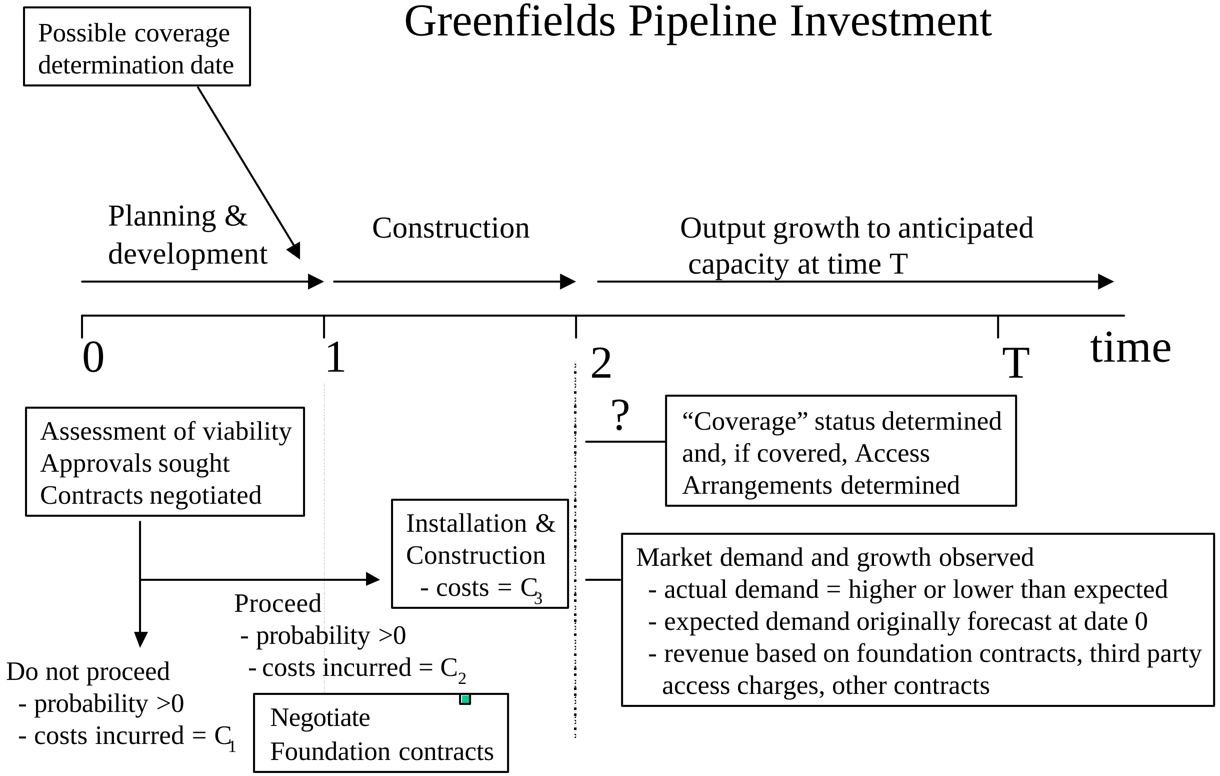
1. At the current time, the CAPM is an appropriate framework for assessing the WACC facing a "greenfields" pipeline. Other asset pricing models involving additional risk factors have been developed in the literature, but the CAPM is currently still the dominant approach adopted in practice for estimating required rates of return.
2. Project finance techniques and financial engineering / risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost. Provided that the capital base concept adopted for use in regulatory price

determination reflects the cost of such risk transfer, or that the cash flows required to insure/ hedge such risks are reflected in operating costs, no further adjustment for risk would appear to be warranted.

3. Specific, ie non-systematic, risks associated with a "greenfields" pipeline should not lead to an adjustment of beta – which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant biases.
4. There are some grounds for believing that the systematic risk of a "greenfields" pipeline may be somewhat higher than that of a mature pipeline, absent regulation. This does not result from characteristics of the variability of the cash flows but is due to the expected longer "duration" of the cash flows and sensitivity of remaining market value to market wide changes in required rates of return. While it is, in principle, possible to decompose cash flow streams into foundation contracts and non-contract components with different risk characteristics, the practical problems of applying such an approach appear to make it infeasible.
5. A CAPM approach to determining WACC and compensating for specific risks in determination of the capital base and / or cash flows appears appropriate. In this regard, it is important to note several matters. First, to provide incentives for appraisal of possible projects or avoid creating disincentives to feasibility studies of investment (and ultimately to investment itself), some allowance for reasonable costs of "failed" project analyses seems appropriate. This is, however, likely to be very small relative to overall construction costs. This could be achieved either by adjusting the appropriate regulatory asset base to be somewhat higher than the accounting based measurement of expenses incurred, or by applying a marginal increase to the required rate of return (perhaps in the order of 5 – 10 basis points). Second, time lags are involved in construction before cash inflows are realized, and project viability requires that those outlays should be compounded at the required rate of return in determining the cost base of the project[14]. Historical accounting costs incurred in construction should be compounded at the required rate of return to give an appropriate current date value for the regulatory asset base.
6. Finally, it should be stressed that access prices derived on the basis of applying a required rate of return to an accounting asset base (at some date 2), conditional on an assumed level of future output which is different to that expected at the time the investment was made (date 1), are not necessarily compatible with providing appropriate signals for investment. If it is possible that the investment will *ex post* (ie at date 2) have a negative NPV due to low demand, and that access will only be sought in cases where demand is high, it is necessary that, in that latter (high demand) case the *ex post* (date 2) NPV will need to be positive if the *ex ante* (date 1) NPV is to be zero. As argued in earlier sections, one potential solution to this problem is to bring forward the coverage/ access determination date such that it occurs early in the project appraisal and development or construction stage rather than after project success has been observed.

[14] For example, if a project involves an outlay of $1 at date 0, has a required rate of return of r, and generates no cash flows until date 2, the required cash inflow at date 2 is $\$1(1+r)^2$ if the project is to have a zero NPV. If target cash flows at date 2 are to be determined at date 1, the appropriate capital base for use at that date is $1(1+r).

Figure 1
Prototype Decision Model for
Greenfields Pipeline Investment



Appendix A – Separating foundation contract and other cash flows

Consider a project which involves a cash outflow today of I_0 and which will generate an uncertain output and thus cash inflow of C_1 in one period's time. (In what follows we assume cash flows are proportional to output. A more thorough treatment would allow for price responsiveness to demand.) The expected rate of return on the project

$$E(r) = E(C_1)/I_0 - 1$$

and the systematic risk of that return

$$ß = cov(r,r_m)/var(r_m)$$

are known.

Assume that a "foundation contract" is signed with a third party (Z Ltd.) in which some fixed part of the project output is provided to that party in exchange for a fixed cash flow of F_1 at date 1. (Z Ltd. might be an end user of the product or an intermediary on-selling the output to the market). The project owner (O Co.) thus receives two sources of cash flow in period 1. One is the risk free cash flow of F_1 which can be converted into a date 0 amount of $F = F_1/(1+r_f)$. (Assume for simplicity that there is no counterparty risk associated with the receipt of F_1 from Z Ltd.). The second, risky, cash flow depends on the direct demand for output (that part of total market demand not satisfied by Z Ltd.) which O Co. supplies.

Note that the foundation contract could take many forms, including terms under which Z Ltd. can resell the output it has purchased should its demand be less than the capacity available to it. (This is particularly relevant where the item in question is a transportation service which is an input service to be combined with an input good to produce a "delivered good" and where ultimate demand is for the delivered good). More generally, the terms negotiated for the foundation contract will reflect the expectations of both parties as to how total uncertain demand for transportation services will split between that met by Z Ltd and that met by directly O Co. For example, market characteristics may be such that there is a "sequential servicing" outcome in which all demand flows through Z Ltd until its capacity under the foundation contract is reached, with O Co. only experiencing positive demand after that point. Alternatively, a "shared servicing" outcome might be anticipated in which demand splits proportionally between Z Ltd. and O Co. As might be expected, the fixed amount F paid under the foundation contract is likely to differ depending on which of these two cases is expected (and be a higher amount in the case where sequential servicing is expected). Note also, that signing of a foundation contract may be undertaken by Z Ltd. with a view to establishing its market position in supplying a delivered good, giving it "first mover" advantages and thus influencing the market characteristics of how final demand for the delivered good will split between suppliers.

Sequential Servicing. The O Co. has a risk free asset (the claim of F_1) which could be sold today for $F_1 / (1+r_f)$ leaving net cash flows of $(-I_0 + F_1 / (1+r_f))$ today. Assuming sequential servicing, uncertain cash flows received by O Co. from meeting demand in excess of that satisfied by Z Ltd., will be Max $[0, (C_1 - F_1)]$ next period. It is clear that the rate of return on the net investment generating the "non-contracted" cash flows will have a higher systematic risk than the total cash flows. (The relationship is:

$\text{cov}(r_u, r_m) = (I_0 /(I_0-F_1/(1+r_f))) \text{cov}(r,r_m)$ where r_u is the rate of return on the non-contracted cash flows).

In this case, it is possible to regard foundation contracts as a form of levered financing of the project. Z Ltd., has provided a capital contribution of present value amount $F_1(1+r_f)$ in exchange for first claim on the cash flows of the project up to a promised amount. The required rate of return for the uncontracted cash flows would be higher than that for the project as a whole, because of the "leverage" effect and could be determined by using some type of levering formula for estimating beta. In valuing the project, it would be possible to separate out the foundation contracts and focus on the systematic risk of the non-contracted cash flows, but this would require subtracting the present value of the contracted cash flows from the asset base.

Shared Servicing. An alternative case is where Z Ltd. pays a fixed amount F_2 for the foundation contract which gives it rights to some proportion α of total potential output. However, market characteristics are such that if total demand is less than potential output, demand is shared between Z Ltd and O Co. in the proportions α and $(1-\alpha)$. Z Ltd is, in this case, effectively an equity partner, since although it has "rights" to a fixed amount, in practice it can only profitably use α of total demand.

Z Ltd will pay an amount equal to the certainty equivalent of the expected value of the uncertain amount involved in purchasing the same output on the spot market at date 1. Suppose α is the proportion of output purchased, then F_2 will be defined by a relationship of the form $F_2 = \alpha[E(C_1) - X]$ where X is the certainty equivalent adjustment factor, and by definition:

$$F_2 /(1+r_f) = \alpha E(C_1)/(1+r)$$

where r is the required rate of return for the project as a whole.
Since the value of the total future cash flows to O Co. is

$$V = F_2/(1+r_f) + (1-\alpha)E(C_1)/(1+r).$$

substitution gives:

$$V = \alpha E(C_1)/(1+r) + (1-\alpha)E(C_1)/(1+r). = E(C_1)/(1+r)$$

The foundation contract cash flows (in this case) would be discounted at the risk free interest rate, and the remaining risky cash flows discounted at the required rate of return for the project as a whole.

These examples draw on the well known Adjusted Present Value technique which implies that it is possible to analyze the NPV of the entire project by comparing the total cost with the sum of the (appropriately discounted) present values of the two separate cash inflows. However, the examples demonstrate that there is no unique approach which might be applied to all cases in practice. The risk adjustments appropriate for determining an appropriate required rate of return for non-contracted cash flows will depend upon the nature of foundation contracts and market characteristics (which in turn may be influenced by the existence of such contracts). Analysis on a case by case basis appears necessary if it is desired to move from analysis based on the systematic risk of the project as a whole to an analysis based on the systematic risk of the project *net of* foundation contract cash flows.

Any such disaggregated analysis would also need to consider whether foundation contracts involving related parties were written on terms which appropriately reflected the risk transfer involved and did not involve value transfers between the parties.

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