Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia

A REPORT PREPARED FOR THE AER

July 2013

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Executive summary

The AER has engaged Frontier Economics, Professor Michael McKenzie and Associate Professor Graham Partington to provide qualitative advice on: what risks should be compensated through the weighted average cost of capital (WACC) when regulating Australian energy networks; how these risks may be measured; and the extent to which the risks identified may differ materially between different types of regulated energy networks.

Our report tackles several questions:

1. What risks might be relevant to a generic regulated network business?
2. How might these risks be managed, either through direct action by the businesses themselves or through design of the regulatory framework?
3. What are the key characteristics of a generic regulated energy network in Australia, what are the risks faced by such a business and, conceptually, how do these compare to risks faced by unregulated businesses?
4. Conceptually, how do the risks faced by regulated water networks in Australia compare with those faced by regulated energy networks in Australia?
5. Conceptually, might there be material differences in the risk exposures of different types of regulated energy networks in Australia?
6. In practice, how might the AER measure the risks that should be compensated through the rate of return?

Risks that may be relevant to regulated networks in Australia

We have identified 14 key risks that a generic regulated network in Australia may potentially be exposed to. These are total risks in the sense that they affect the variation of the firm's cash flows/returns. These risks may be categorised into two broad groups:

- **Business risks** (factors that affect the riskiness of the underlying assets of the firm). These include demand risk, input price risk, cost volume risk, supplier risk, inflation risk, competition risk, stranding risk, political/ regulatory risk and other business risks.

- **Financial risks** (arising as a consequence of how the business's activities are funded). These include refinancing risk, interest rate reset risk, liquidity risk, default risk and financial counterparty risk.

The risks identified above are not exhaustive but, in our view, are likely to be the most relevant to regulated utilities. We also note that these risks are also faced by unregulated businesses. However, the level of exposure to these risks may differ between regulated and unregulated firms, and between sectors and industries.

We also consider a number of features of a business that may amplify or mitigate these risks. These features include the level of financial gearing, the degree of operational gearing, size and ownership/scope of activities. We find that increasing financial gearing and operational gearing raises the level of risk faced by businesses.

There is some (mixed) evidence that investors demand higher rates of return when investing in small firms than in large firms.[1] However, there is no compelling, widely-accepted theory that explains why this could be so. Furthermore, none of the empirical evidence available relates specifically to utilities. Therefore, even if the size premium is real, it is unclear to what extent such premiums are applicable to regulated utilities.

We do recognise that one possible explanation for a size premium is that small companies are generally less liquid than large firms. There is some regulatory precedent for regulators allowing so called 'small company premiums' to reflect illiquidity, as well as allowances that recognise that small firms might face higher transaction costs than large firms when accessing capital markets. McKenzie and Partington (2013) argue that allowances for transaction costs, if made at all, should be provided through the regulatory cash flows rather than through the allowed rate of return.

We have also given consideration to submissions that large firms and state treasury corporations, who need to manage refinancing and interest rate reset risks for large quantities of debt, find hedging difficult under the current regulatory arrangements. The key concerns raised by these parties are that the Australian market for interest rate swaps (IRS) is illiquid, and that attempting to lock-in rates over a relatively short period of time creates the risk of opportunistic manipulation by market participants. We agree that it is prudent to stagger refinancing of debt over a period of time rather than roll-over large quantities of debt at once. However, it is unclear to us that the IRS market in Australia is so illiquid as to limit severely the hedging opportunities that large debt managers require. Further, given the over-the-counter nature of the IRS market, it is not obvious that the risk of manipulation is large. However, these are empirical questions and we recommend that the AER investigate further through more detailed engagement with the parties who have raised concerns, and with banks.

1 Some recent evidence suggests that these so-called 'size premiums' have fallen or disappeared altogether in recent times. In addition, there is some evidence that the size premium in Australia has been negative. On the whole, the empirical evidence is inconclusive.

On the question of ownership, it is well-recognised in finance theory that the cost of capital of a project depends on the risk characteristics of that project and not the overall cost of capital of the firm that owns the rights to that project. This is why the cost of capital of a government-owned business is generally believed to be the same as the cost of capital of an otherwise identical firm in the private sector. However, it is also a practical reality that a large group may be able to raise finance more cheaply than its subsidiaries. This is usually a question of liquidity and access to capital markets. If it is clear that a subsidiary has no choice but to raise finance on its own (e.g. because of financial ring-fencing provisions imposed by the regulatory framework), and cannot do so more cheaply than its parent, in our view it is reasonable to make allowances for illiquidity and larger debt-raising costs.

Mechanisms for managing and allocating risks

Regulated firms' actual exposure to business and financial risks depends on the extent to which these can be managed. We identify several ways in which businesses can and should manage these risks. Some of these mechanisms — such as hedging, insuring and contracting — involve sharing risk with third parties (e.g. financial counterparties, customers and suppliers). Companies may also be able to exercise flexibility over the timing of key decisions in a way that allows the resolution of future uncertainty. Regulated businesses should not be rewarded for failing to take prudent and efficient steps to manage their risks.

It is important to not overlook the important role that the regulatory framework plays in facilitating the management of risks. The regulatory framework defines the 'rules of the game'. These rules influence not only the level of risk that businesses bear, but also how these risks may be distributed between different groups. We identify several mechanisms that regulators can build in to the regulatory framework that effectively shares risk between customers and businesses. We give several examples of how these mechanisms have actually been applied overseas. Most of these mechanisms are employed in some form in Australia.

Risk exposure of regulated energy networks in Australia

We survey several of the key economic features of regulated energy networks that may influence the risks they face. Firstly, most energy networks are natural monopolies to varying degrees, which effectively rules out facilities-based competition in many cases. Secondly, the networks face very little competition or by-pass risk, and so are generally insulated from competition from other sources. By-pass of existing networks only tends to occur on the margin. Certain gas transmission pipelines may be the exception, as a result of the development of an LNG export industry in Queensland. Thirdly, the networks comprise long-lived assets, which has implications for how the businesses finance their activities. Finally, energy networks are characterised by relatively slow rates of technological change, which removes much of the stranding risk that businesses in other sectors face.

The form and nature of regulation applicable to Australian energy networks mitigates most of the business risks they face as compared to the business risks faced by other types of firms in the economy. Regulated revenues are set on a periodic basis and changes in volumes may only affect the timing of revenues (under a revenue cap). Even where revenues fall short of expectations due to lower volumes (as under a price cap), the lower volumes imply that costs would probably also have been lower than expected. Unanticipated or poorly-managed changes in costs are partly borne by customers and only partly by the network business through the building block form of incentive regulation that applies. Stranding and optimisation risks are minimal for energy networks, a complete contrast to businesses operating in other sectors.

Comparability of the total risks of water and energy networks

There are many similarities between the characteristics of regulated water and energy networks. They both have strong natural monopoly features and are characterised by slow technical progress and long-lived assets. Many of the risks faced by the two types of networks are also similar.

However, there are two principal differences between the two sectors:

- Regulated water networks are exposed to greater supply-driven volume risk, arising from uncertainty about future water availability, than are regulated energy networks.

- Government plays multiple roles in the water sector (as owner, rule-maker and, in many cases, regulatory decision-maker). This increases the scope for conflicts of interest and political/regulatory risk. By contrast, government plays a much smaller role in the energy sector.

Notwithstanding these differences, regulated water networks in Australia are probably the closest comparators available to regulated Australian energy networks. Given the similarity of their activities and characteristics, water networks and energy networks are, in principle, reasonable comparators to one another.

A lack of share price data on regulated water businesses in Australia rules out the use of direct market information on water networks to inform the AER's assessment of the risks of energy networks. Given these data limitations, regulators of water companies in Australia often use the AER's analysis of the risks of energy networks to inform their WACC determinations. To avoid introducing circularity into its analysis, we recommend that the AER not rely on precedent from Australian regulators of water businesses to inform its estimate of covariance risk for energy networks.

The most promising source of evidence on the covariance risks of water companies is overseas, where market data are available. However, the AER should use this evidence carefully since the characteristics and risk profiles of regulated water companies overseas may not match those of their counterparts in Australia.

Comparability of the total risks of different types of energy networks

We have undertaken an assessment of the extent to which different types of regulated energy networks in Australia may be exposed to the risks identified in this report. In general, we believe there are some reasons to think that regulated gas transmission pipeline networks may be somewhat riskier than other types of regulated energy networks. This is because gas transmission pipelines are more heavily dependent on a relatively small number of large industrial customers than either gas distribution or electricity networks. Further, the development of new pipelines serving the nascent LNG export industry is likely to lead to changes in gas flows through eastern Australia and higher gas prices, which may encourage consumers to switch from gas to electricity. Under these conditions, some gas pipelines may face greater by-pass threats than other gas networks or electricity networks generally. However, this is not a strongly-held view, as aspects of the incentive regulatory arrangements provide more certainty to gas networks than electricity networks. Ultimately, the question of whether gas transmission pipeline networks are riskier than other types of energy networks needs to be answered empirically.

Measurement of risks that should be compensated through the rate of return

In a separate report to the AER, Professor McKenzie and Associate Professor Partington (McKenzie and Partington, 2013) explain that it is not total risk that should be compensated through the rate of return but, rather, risks that cannot be eliminated by the marginal investor through diversification.[2] McKenzie and Partington (2013) refer to these risks as 'covariance risks' because the 'price' of these risks depends on the covariance of the firm's cash flows with broader, systematic factors.

It is possible to measure the *individual* risks identified in our report. However, doing so does not help to answer the key question posed by the AER: *how should the risks to be compensated through the WACC be measured?* This is because the quantification of individual risks provides no concrete information on the level of covariance risk that investors in the business are exposed to. In order to

2 McKenzie, M., Partington, G. (2013), *Risk, asset pricing models and WACC*, June.

understand that, it is necessary to apply empirically one or more of the asset pricing models surveyed in McKenzie and Partington (2013).

For a given firm, facing a given set of circumstances, the estimated covariance risk will differ depending on the model employed. This is because different models specify different factors as being relevant to investors. In the Sharpe-Lintner version of the Capital Asset Pricing Model (CAPM), there is single 'market' factor. In other models there may be multiple relevant factors. Given that there are a number of possible asset pricing models to choose from, it is not possible to say, a priori, which (or what proportion) of the total risks identified in our report should be compensated through the rate of return. Rather, this is a question that needs to be answered empirically. As such, the key issue is whether the AER has a sound framework for estimating covariance risk.

We recommend a three-step 'comparator approach' that the AER may use to measure covariance risk. This approach is particularly amenable to the estimation of the cost of equity, but could be adapted to also assist in the estimation of the cost of debt. Our recommended approach builds on the AER's existing methodology. The main steps are:

1. **Identify a group of comparator firms that share similar risk characteristics to the business of interest, for which good market data do exist.** In this context, the 'business of interest' would be the benchmark efficient entity or entities, to be defined by the AER. The AER could use our assessment of risks for regulated energy networks to identify suitable comparators.

2. **Apply an asset pricing model or models to the comparator data to estimate the level of covariance risk exposure faced by the comparators.**

3. **Translate the estimate of covariance risk for the comparators into a suitable estimate for the business of interest.** This may involve adjusting the covariance risk estimate up or down in order to obtain a better estimate of the covariance risk relevant to the business of interest. Given the relatively paucity of share price data on Australian energy networks, it may be necessary to use data from overseas in order to do this. We explain how data on overseas companies could be used to test empirically if gas pipeline transmission networks are likely to be riskier than other types of energy networks.

1 Introduction

The AER has engaged Frontier Economics, Professor Michael McKenzie and Associate Professor Graham Partington to provide qualitative advice on: what risks should be compensated through the weighted average cost of capital (WACC) when regulating Australian energy networks; how these risks may be measured; and the extent to which the risks identified may differ materially between different types of regulated energy networks.

The AER is currently developing, in consultation with stakeholders, guidelines on how it intends to estimate WACC in future determinations. As part of the process of developing the guidelines, the AER must:

- Define the benchmark efficient entity; and
- Identify the degree of risk to which it is exposed in the provision of standard control services.

Although our advice will feed in to the AER's task of defining the benchmark efficient entity, we have not been asked to address that question. Rather, our work relates more directly to the second of the tasks above.

The AER has structured this assignment into three parts, which are:

Part A. Identify what risks should be compensated through the rate of return on capital.

Part B. Identify what risks might be relevant when determining the WACC for a generic regulated network business, and explain how these risks may be measured.

Part C. From the long-list of risks identified in Part B, identify the risks that might be material to regulated energy networks in Australia, and assess qualitatively how the exposure to these risks might vary between different types of networks.[3] In addition, assess how the risks of regulated water networks compare to those of regulated energy networks.

Associate Professor Graham Partington and Professor Michael McKenzie have taken primary responsibility for Part A of this assignment, to which end they have produced a separate report entitled *Risk asset pricing models and WACC* (henceforth, McKenzie and Partington, 2013). Our report tackles Part B and Part C and, in doing so, draws on insights from McKenzie and Partington (2013).

Our report is structured as follows:

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3 The different network types are electricity transmission, electricity distribution, gas transmission and gas distribution.

- Chapter 2 identifies, defines and discusses the different types of risk that a generic regulated network (i.e. a network that may or may not be an energy network) might potentially be exposed to.

- Chapter 3 explores how these risk exposures might be managed, either through action by the businesses themselves, or through the design of the regulatory framework.

- Chapter 4 outlines the general economic features of energy networks, discusses the extent to which Australian energy networks in general may face the types of risks identified in Chapter 2, and draws conclusions on how these risks compare with: (a) other firms in the economy; and (b) regulated water companies.

- Chapter 5 discusses the key differences in the economic characteristics of different types of energy networks and evaluates the extent to which the various types of networks face similar or different levels of exposure in respect of various types of risk.

- Chapter 6 sets out a practical framework that the AER could use to measure the risks that should be compensated through the WACC.

Finally, we acknowledge gratefully the helpful comments provided to us by Professor McKenzie and Associate Professor Partington on various aspects of our report. The views expressed herein remain Frontier's.

2 Risks that may be relevant to regulated networks in Australia

This Chapter explores the individual risks that could potentially be relevant to a generic regulated network in Australia. We begin by enumerating a long list of possible risks and describing how they may be relevant to regulated network businesses. Next, we consider a number of possible features of regulated businesses that may either amplify or mitigate these risks. Then, we discuss the issue of risk measurement. Finally, we discuss the circumstances in which certain risks should not be compensated in order to promote efficient economic outcomes that are in the long-term interests of consumers.

2.1 Identification of potential risks

The systems of economic regulation that prevail in Australia, as in many other countries, are largely ex ante in nature: regulators must determine allowances based on forward-looking assessments of costs and, in the case of price-cap regimes, customer demand. The regulated businesses themselves also make investment, contractual and financing decisions that involve assessments about the future based on incomplete information available today.

Since neither regulators nor regulated businesses enjoy perfect foresight, there is always the possibility that actual future outturns will not match ex ante assessments. This potential mismatch of expectations and future outturns gives rise to risks, which are borne by the businesses in the first instances. However, as we discuss in Chapter 3, there may be strategies the businesses can employ, or mechanisms that regulators can put in place, that can allow the firms to manage and share these risks with customers and others.

We have identified 14 risks that a generic regulated network may potentially be exposed to. These may be categorised into two broad groups: business risks (which are factors that affect the riskiness of the underlying assets of the firm); and financial risks (which arise as a consequence of how the business's activities are funded). These risks are summarised in Table 1, and are discussed further below.

It is important to note that almost all of the potential risks identified are common to regulated and unregulated businesses. However, the level of exposure to these risks may differ between regulated and unregulated firms, and between sectors and industries.

Table 1: Summary of potential risks that a regulated network may be exposed to

Business risks	Financial risks
Demand risk	Refinancing risk
Input price risk	Interest rate reset risk
Cost volume risk	Illiquidity risk
Supplier risk	Default risk
Inflation risk	Financial counterparty risk
Competition risk	
Stranding risk	
Political / regulatory risk	
Other business risks	

Source: Frontier Economics

Finally, we recognise that the list of risks identified above may not be completely exhaustive. However, we think that these are likely to be the most material risks for a regulated network business. We now discuss each of these risks in turn.

2.1.1 Demand risk

Demand risk (also sometimes referred to as 'volume risk') refers to the risk that actual future demand for a firm's output does not match forecast demand. Regulated and unregulated businesses alike may be exposed to demand risk. The materiality of demand risk for a regulated business depends on the form of regulation employed.

Under a system of **price-cap regulation**, prices or tariffs are adjusted by the regulator over time (usually in line with inflation, and building in efficiency improvements). Under a price cap system, the regulator must develop demand forecasts for the forthcoming regulatory period in order to convert allowed revenues to regulated prices. To the extent that the regulator's demand forecasts are subject to forecasting error, the regulated business faces demand risk. Under the alternative system of **revenue-cap regulation**, the regulator determines a level of maximum allowed revenue that the business may earn over the regulatory period.

The key difference between a price cap and revenue cap lies in the factors that result in adjustments to prices. Under a revenue cap prices in each year can be adjusted by the business to take account of variation in volume outturns compared to forecast volumes. This means that, in principle, under a revenue cap the business would recover a specified level of revenue, irrespective of actual demand. In addition, many revenue cap regimes incorporate an ex post revenue correction mechanism, which adjusts revenues for over- or under-recovery of revenues in the present control period.[4] Finally, under a revenue cap system, provided the regulatory framework affords firms the flexibility to do so, the businesses may structure their tariffs within the revenue cap in such a way as to minimise the impact of revenue volatility.[5] These features largely remove the revenue risk associated with unanticipated changes in volumes.

In addition, a revenue cap scheme can help dampen the effects of demand uncertainty on profits by allowing a flow-through of demand to total variable costs:[6]

> Second, when actual demand deviates from expected demand, the 'flow-through' effect on total variable cost dampens the impact of the revenue variance on profit. Specifically, if actual demand is lower (higher) than forecast demand then the firm's actual variable cost is lower (higher) than it would be than if forecast and actual demand were equal. As a result, the decrease (increase) in total variable cost will dampen the impact of the variance in the firm's revenues on its profits.

The relative advantages and disadvantages of price caps vs. revenue caps are explored in section 3.2.

Another dimension to demand risk is investment/expenditure risk. This derives from the need for businesses to forecast demand in order to determine how much should be invested in capital equipment or spent on maintenance and operations. If companies underestimate demand and, consequently, invest less than required to serve demand, the businesses will earn less revenue than if demand had been forecast accurately. Conversely, if companies overestimate future demand and invest too much, the businesses will earn more revenue than if demand had been forecast accurately. Of course, this assumes that all planned investment is approved by the regulator, and that the regulator does not disallow recovery of sunk investments if they turn out to be surplus to requirements.

2.1.2 Input cost risk

Under systems of ex ante regulation, the regulator must either make or approve business' forecasts of input costs. These input costs, which comprise operational expenditure and capital expenditure, depend on the unit price of input costs, as well as the overall volume of costs (i.e. the quantity, or number of units, required of a particular input).

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4 See, for example: Ofwat (2010), *The form of the price control for monopoly water and sewerage services in England and Wales – a discussion paper*, October.

5 For instance, the businesses may employ two-part tariff pricing, with a relatively high fixed charge component. By ensuring a more fixed, rather than variable, stream of revenues, the business may be able to mitigate the effect of uncertain future demand on revenues.

6 QCA (2012), *Risk and the form of regulation: Discussion paper*, November, p.13.

Businesses can face future uncertainty over the unit prices of inputs. As a result, actual outturns may deviate from cost forecasts. Examples of uncertainty over unit prices include the following:

- The prices of many of the raw inputs to production for many firms (e.g. fuel, construction materials) are determined in global commodity markets. In recent times there has been a significant increase in price volatility in global commodity markets,[7] which can make accurate forecasting of input costs challenging.

- The cost of inputs to production sourced from overseas may be affected by unexpected changes in exchange rates (i.e. exchange rate risk).

- The cost of skilled labour (e.g. network engineers) may be subject to skills shortages, which can be difficult to predict over a lengthy price control period.

Deviations between forecasts and outturns can arise due to factors that are controllable and non-controllable from the point of view of the firm. For instance, actual costs may exceed expectations because the business was less efficient at managing its costs than expected. Under a system of incentive regulation, such cost over-runs ought not to be rewarded.

However, some costs (such as those provided as examples above) may be largely beyond the firm's control. That is not to say, however, that such costs are *entirely* beyond the control of firms. It may be possible for many firms to employ hedging instruments (e.g. futures and forward contracts, swaps) that can smooth volatility in input costs and exchange rates. However, it is important for regulators to recognise that:

  - the *source* of many uncertainties are factors beyond the control of the firms;
  - certain firms (e.g. small businesses) may have difficulty accessing financial markets that allow these risks to be hedged effectively; and
  - there are direct costs (e.g. transaction costs, professional fees) associated with employing hedging instruments.

2.1.3 Cost volume risk

Businesses can also face uncertainty about the quantity of inputs required in order to deliver certain outputs. For example:

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7 See, for example, UNCTAD (2012), *Excessive commodity price volatility: Macroeconomic effects on growth and policy options*, April.

- Projects may take longer to complete than anticipated originally (e.g. due to unforseen engineering difficulties or complexity; or due to delays in sourcing materials, labour and other inputs).

- Greater quantities of construction/production materials may be required than were forecast initially.

Cost volume risk can be a major contributor to time and/or cost overruns related to large capex or construction projects (usually referred to as 'construction risk'). Construction risk is often a problem with 'first-of-a-kind' builds (where the firm has little prior experience to draw on), or with particularly large and complex projects.

Regulators may reduce the impact of construction risks on the business by allowing capital work in progress (CAPWIP) to be included within the regulatory asset base (RAB), i.e. by incorporating capex spend in the RAB on an 'as-incurred' basis, rather than when assets are commissioned. Indeed, this could be a tool used by regulators to encourage firms to undertake capital investments that might otherwise be deferred due to construction risk. However, such an approach may also weaken the incentives for businesses to complete capital projects in a timely and efficient fashion (e.g. through careful contracting and effective monitoring throughout the construction process). Alternative approaches might involve allowing partial inclusion of CAPWIP in the RAB, or permitting full inclusion of CAPWIP but with the imposition of ex post penalties if the investments are delivered late.

2.1.4 Supplier risk

Supplier risk relates to the possibility that third party suppliers of inputs that the business has contracted with fail to deliver the products and services agreed upon. Supplier risk can arise in relation to physical goods (such as commodities used as inputs to production) as well as services (e.g. from contractors).

Supplier risk can impose direct costs on a business:

  - in the event that the business is forced to source from alternative suppliers of inputs, and must pay a premium when doing so (e.g. for short-notice supply, or if alternative suppliers are less cost-effective);

  - due to the search costs associated with identifying alternative sources of supply; and

  - through production time delays, particularly if the delivery failure occurs unexpectedly, and if the failure relates to a critical input to production.

2.1.5 Inflation risk

Inflation risk relates to the possibility of a mismatch between expected inflation and realised inflation, the difference between the two being unanticipated inflation. Inflation represents the erosion in the value of purchasing power over time as the general level of prices in the economy changes. Ultimately, investors in any asset, regulated or otherwise, will be interested in their expected returns after inflation. Therefore, a sound regulatory framework should make allowance for inflation to ensure that the real value of the capital invested is preserved over time. If the regulatory framework allows for forecast inflation only, regulated businesses would be exposed to inflation risk. However, if the regulatory framework adjusts prices/revenues over time based on actual inflation, inflation risk will be minimised.

2.1.6 Competition risk

Competition risk refers to the threat of new entry or expansion by existing rivals, which would increase the extent of competition that the business is exposed to. In general, competition risks for regulated networks are very low. Such networks are usually regulated in the first instance because they are deemed, by virtue of their natural monopoly status (i.e. large scale economies and high barriers to entry), to wield significant market power. It is precisely because of these natural monopoly features that facilities-based competition emerges rarely in such industries. Economic regulation is an attempt to redress the attendant market failure that typically follows.

However, it is sometimes possible for competition to emerge in network industries that have natural monopoly characteristics. For example:

- Competition in mobile telephony markets (i.e. from rival network entrants, as well as from mobile virtual network operators, MVNOs) has been introduced successfully in many countries, including Australia.
- Competition in fixed telephony markets has also been encouraged by the unbundling of local loops, and by promoting third party access to existing network infrastructure. Again, this has occurred in many parts of the world.
- In the US, interstate and intrastate competition between gas pipeline networks has been introduced successfully with the promotion of greater market integration, as well as the promulgation of policies such as "a combination of unbundling, flexible short-term rate setting, strong property rights for holders of contractual capacity, and controlling the abuse of market

power".[8] This is in contrast to Europe, for instance, where competition between gas transmission networks is yet to develop.[9]

All three of these examples have one thing in common: the introduction or promotion of competition occurred only as a result of some change in regulatory approach or policy intervention. For instance, as Malkholm (2007) argues, it was the change in institutional arrangements in the US that prompted competition to emerge. In contrast, lack of similar action in Europe has caused networks there to continue on as regulated natural monopolies.

Although competition in unregulated industries may emerge naturally, this is unlikely to occur in regulated industries. Therefore, regulated networks generally face low competition risk, and any risk of competition emerging may be better thought of as a form of regulatory risk (i.e. the risk of regulatory intervention to introduce or promote competition). The scope for energy networks to face competition is discussed in Chapter 4.

2.1.7 Stranding risk

Stranding risk refers to the possibility that the actual economic lifetime of an asset (i.e. the period over which the asset generates economic returns) falls short of its expected economic lifetime. When the actual demand for, or utilisation of, the asset over its lifetime is lower than expected, the owner of the asset will be unable to recoup their full investment.

Stranding risk is particularly relevant in industries where rapid technological progress can render existing assets obsolete quickly. It is also particularly relevant to industries in which future demand or customer penetration is highly uncertain. For these reason, stranding risk has featured prominently as an issue for regulated telecommunications networks, and particularly for those networks that employ nascent technologies.

For instance, many countries around the world have recently been promoting the rollout of next generation fibre communications networks. However, telecommunications operators have resisted calls to invest privately and widely in such networks, in large part because of significant uncertainty over future demand for services delivered over fibre networks once built.[10] In recognition of

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8 Jamasb, T., Pollitt, M., Triebs, T. (2008), 'Productivity and efficiency of gas transmission companies: A European regulatory perspective', *Energy Policy* 36(9), 3398–3412.

9 von Hirschhausen, C. (2006), 'Infrastructure investments and resource adequacy in the restructured US natural gas market – is supply security at risk?', *MIT Centre for Energy and Environmental Policy Research working paper* 06-1-018; and Malkholm, J. D. (2007), 'Seeking competition and supply security in natural gas: The US experience and European challenge', *NERA report*, June 13.

10 See, for example, OPTA (2008), *Policy rules tariff: Regulation for unbundled fibre access*. December. Another major reason that operators have cited for deferring investment in fibre networks relates to the regulatory proposal that such networks should be opened up to competition immediately once

these concerns, the European Commission has recommended to national regulatory authorities (NRAs) in Europe that:[11]

> Investment risk should be rewarded by means of a risk premium incorporated in the cost of capital... NRAs should, where justified, include over the pay-back period of the investment a supplement reflecting the risk of the investment in the WACC calculation currently performed for setting the price of access to the unbundled copper loop.

and that, in doing so, the NRAs should ensure that the risk premium applied reflects, among other things, "uncertainty relating to retail and wholesale demand".

The materiality of stranding risk for a regulated network depends in large part on the regulator's chosen treatment of the regulatory asset base (RAB). Certain telecommunications regulatory frameworks involve the regulator 'optimising' the asset base periodically by removing from the RAB elements of the network deemed to redundant or inefficient (compared to prevailing technologies), even if those investments were efficient at the time they were made.[12] This effectively strands the elements of the network that have been optimised out as the firm is no longer permitted to earn a return on those assets.

In contrast, most energy regulators, including the AER, have committed to preserve RAB over time by not re-optimising it periodically. This has the effect of virtually eliminating the businesses' exposure to stranding risk.

2.1.8 Political/regulatory risk

Political/regulatory risk is the additional variation in returns that a firm is exposed to given the actions of external decision-makers (i.e. the government and/or a regulator). The government (and its various branches) is responsible for making and enforcing the laws that determine not only the regulatory

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built, which the operators argue has the effect of truncating upside returns if the investment turns out to be profitable, but leaving them exposed fully to downside risks should the investment fail commercially.

11 European Commission (2010), 'Commission recommendations of 20 September 2010 on regulated access to Next Generation Access Networks (NGA)', *Official Journal of the European Union* 2010/572/EU.

12 Network optimisation of this type has focussed on two approaches: the **scorched earth** approach, which involves a full redesign of the network using the most efficient technologies available at the time, regardless of whether the original network was built efficiently; or the **scorched node** approach, which holds certain key elements of the network fixed, with the remaining elements being redesigned periodically using current technologies. These approaches have rarely been employed when regulating energy networks. Two exceptions that we are aware of include Spain (which uses a scorched earth approach to RAB when determining regulated prices for electricity distribution networks), and Sweden (which uses a scorched earth approach to RAB when undertaking periodic cost efficiency assessments of incumbent electricity distribution networks). See Deloitte (2011), *Bottom up modelling for the water industry: A report for Ofwat*, April.

framework within which the firm must operate, but also every other commercial aspect relevant to the business (e.g. taxation policies, the value and protection of property rights, and the way in which it interacts with other economic agents). The regulator, constrained within the laws and policies developed by the government, must design, implement and oversee the regulatory framework within which regulated businesses must operate.

Examples of types of political risk include:

- The introduction of new policies (e.g. environmental initiatives that encourage energy efficiency, or the introduction of government support for certain renewable technologies that could have an impact on demand for energy network services);
- The introduction of new legislation that result in windfall losses or windfall gains to firms, or generally alter businesses' costs;
- Changes in tax policy.

Regulatory risk may manifest as (expected or unexpected) changes to the regulatory framework that have a material impact on firms' returns.

The materiality of political/regulatory risk depends on the level of discretion enjoyed by decision-makers and the predictability of the decision-making process.

Predictable regulatory change can alter company risk by altering the sensitivity of firms' allowed cash flows (and, therefore, returns) to market movements. For example, the regulatory regime may encourage firms to undertake major network expansion and upgrades (e.g. to deal with growing demand or to meet government policy objectives). Major investment programs usually result in an increase in financial gearing (i.e. a higher level of debt as a proportion of enterprise value) and operational gearing (i.e. a higher ratio of fixed to variable costs). This would raise the cost of equity.

In addition, the introduction of a set of rules designed to help manage the impact of market shocks on the business (e.g. price control reopeners) could be expected to lower the systematic risk of businesses, provided that investors are clear about how these rules will work. For example, Clarke (1980) examines how the introduction of the fuel adjustment clause (FAC) affected the systematic risk of electric utilities in the 1970s.[13] The FAC was a mechanism that allowed US regulated utilities to pass through increased cost of fuel automatically by adjusting the price of electricity charged to consumers. Clarke finds that the systematic risk of firms that were able to use the FAC decreased by approximately 10%.

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13 Clarke, R., G., (1980), 'The effect of fuel adjustment clauses on the systematic risk and market values of electric utilities', *Journal of Finance* 35(2), 347-58.

Several empirical studies find significant effects of regulation on the regulated firms' cost of capital. Trout (1996), Archer (1981) and Dubin and Navarro (1982) compared utilities in different US states to investigate the effect of variations in state-level regulations on the cost of capital.[14] These regulations can differ in terms of known rules around the length of regulatory lag between reviews or the use of automatic adjustment clauses for certain cost components. A favourable regulatory climate is associated, among other things, with a shorter regulatory lag and higher cost pass-through. All these studies find that regulatory climate has a significant effect on the cost of capital.

Uncertainty over the future expected behaviour of the regulator can also affect the cost of capital for the regulated firm. A few studies have examined the effect of regulatory uncertainty created by UK general elections in which different parties promised to implement different systems of regulation were they to win office. The studies suggest that political/regulatory uncertainty can have a material impact on the cost of capital of regulated firms (see Box 1).

Certain regulatory measures and institutional arrangements can help reduce political/regulatory risk.

Commitments by the government/regulator, coupled with consistent, observable and repeated behaviour that lends credibility to the commitments, can help reduce political/regulatory uncertainty. Credible undertakings around how the regulator intends to exercise discretion in future are particularly helpful (although as discussed in section 3.2, other forms of commitments can also be useful in mitigating regulated firms' risk exposures).

For example, when developing its current regulatory framework, the UK energy regulator, Ofgem, recognised the potential for tension between the need for a flexible/adaptable regulatory framework, and the need to provide stakeholders with clarity and certainty. Box 2 provides a summary of the commitments that Ofgem has made in order to strike a balance between these two objectives.

In addition, governance arrangements that separate rule-making and rule-enforcement should, in principle, also reduce the risk of discretionary and unpredictable regulatory decisions.

Finally, a clear process that provides stakeholders a way of to challenge unreasonable regulatory determinations should also, in principle, lead to more careful decision-making.

14 Trout, R. R., (1979), 'The regulatory factor and electric utility common stock investment values' *Public Utilities Fortnightly*, November 22 1979, 28-31; Archer, S. H., (1981), 'The regulatory effects on cost of capital in electric utilities', *Public Utilities Fortnightly,* February 26 1989, 36-9; Dubin, J., A., Navarro, P. (1982), 'Regulatory climate and the cost of capital', in *Regulatory reform and public utilities*, ed. By Michael A. Crew, Boston/Dordrecht/London, 141-66.

Box 1: UK studies of the impact of political/regulatory uncertainty on the risks faced by regulated businesses

Antonio and Pescotto (1997)[15]

Antoniou and Pescotto (1997) examined the effect of the 1987 and 1992 UK general elections on the beta of British Telecom (BT). They found that in the build-up to the 1987 election, there was a statistically-significant increase in BT's beta, whereas in the lead-up to the 1992 election they detected a statistically-significant reduction in BT's beta. In both elections the outcome was a victory for the Conservative Party. The authors argue that the difference in results, in terms of the impact on beta, could be explained by a change in Labour's intentions towards the regulation of the telecommunications sector between the two elections. In 1987 Labour's manifesto promised the renationalisation of the telecommunications industry, whereas in 1992 Labour had removed this pledge. The authors also investigated the impact of a large number of regulatory actions relating to the development of regulation and competition policy as applied to BT. The paper finds that these events have a material impact on the estimated beta for BT, both positive and negative.

Buckland and Fraser (2001)[16]

Buckland and Fraser (2001) studied the impact of the 1992 UK general election on the betas of 12 regional electricity companies (RECs), which were privatised in 1990. The fourth consecutive Conservative victory at those elections was a surprise outcome. In the lead up to the election, polls had Labour consistently ahead of the Conservative party. Labour had campaigned to impose increased public control over the utilities industries and tighter regulation. In the month leading up to the election on 10 April, speculation of a Labour victory was intense, and Conservative MPs warned their supporters of a possible loss. Buckland and Fraser found statistically-significant evidence of the betas of the RECs rising significantly during this period, peaking on the day of the election, in anticipation of stricter regulation to come. This would have had the effect of raising the RECs' costs of capital, all else being equal.

Grout and Zalewska (2006)[17]

In 1997, the newly elected Labour government proposed an overhaul of the UK regulatory framework, which would replace price-cap regulation with explicit profit sharing between companies and customers. In principle this move should have reduced the risk borne by investors. After a period of 25 months, however, the government abandoned the plan. Grout and Zalewska (2006) study the effect of this announcement on regulated firms' betas. They compare the betas of UK regulated companies (telecommunications, water, electricity, and airports) with those of a control group of similar companies in the US during the period that the proposed change was being considered. In other periods, the US and UK betas were found to be very similar. However, during the period the UK government was evaluating the change, the betas of the two groups of companies diverged significantly, with the betas of the UK firms declining (relative to those of the US firms) as anticipated. This suggested that the proposed regulatory reform had a significant difference on the systematic risk of the regulated UK firms.

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15 Antoniou, A., Pescotto, G. (1997). 'The effect of regulatory announcements on the cost of capital of British Telecom', *Journal of Business, Finance & Accounting* 24(1), 1-25.

16 Buckland, R., Fraser, P. (2001), 'Political and regulatory risk: beta sensitivity in UK electricity distribution', *Journal of Regulatory Economics* 19(1), 5-25.

17 Grout, P. A., Zalewska, A. (2006), 'The impact of regulation on market risk', *Journal of Financial Economics* 80(1), 149-184.

Box 2: Ofgem's approach to regulatory uncertainty under its new RIIO framework

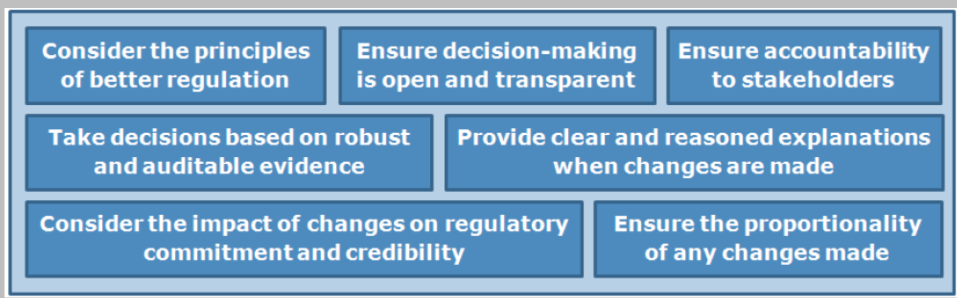
In October 2010 Ofgem completed RPI-X@20, a comprehensive review of the system used to regulate energy networks in Great Britain. As a result of this review, Ofgem decided it would move to a new system of regulation known as RIIO. Ofgem has published a RIIO Handbook, which sets out its principles for implementing the RIIO framework.[18]

The Handbook explains that Ofgem expects the RIIO model to be long-lived, but that it may need to be adapted over time in order for it to remain fit for purpose. Crucially, however, Ofgem recognised explicitly that along with the benefits that come with an adaptable system:

> …there are potential downsides in terms of the impact on regulatory commitment and certainty. We will therefore be transparent about how adaptation could take place. We will seek to ensure consistency with the principles of better regulation when making any modifications to the RIIO model.

The principles of better regulation referred to by Ofgem are summarised **Figure 1** below.

Figure 1. Principles to adopt in adapting the RIIO model



Source: Ofgem (2010), Handbook for implementing the RIIO model, 4 October, p.12

These principles are all designed to minimise regulatory uncertainty. In order to satisfy these principles, Ofgem made the following commitments:

- publication of reports following price control reviews summarising lessons learned, including the effectiveness and transparency of the process and recommendations for future reviews;
- ongoing monitoring and publication of company performance in delivering against primary outputs and of the rewards they have earned from doing so, using the Regulatory Reporting Packs as the basis for collection of information; and
- adopting best practice knowledge retention procedures, including keeping and sharing records of data, discussions, and decisions from one review to the next.

The RPI-X@20review itself took two years to complete, during which time Ofgem communicated its intended policy changes well and sought stakeholder views before finalising the RIIO approach.

2.1.9 Other business risks

Businesses may face exposure to other business risks arising from low-probability events that may have a large impact on the cash flows of the business. Examples of such events may include: major or catastrophic losses arising from natural disasters (e.g. bush fires, storms, floods) or damage caused by third parties (e.g.

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18 Ofgem (2010), *Handbook for implementing the RIIO model*, 4 October

terrorist attacks); fraud losses; and losses arising from liability for damages to third parties (e.g. liability for damage to the environment, or arising through litigation). Most of these types of risks should be considered business or industry specific and, therefore, largely diversifiable from the perspective of the marginal investor.

2.1.10 Refinancing risk

Refinancing (or roll-over) risk derives from the fact that interest rates are volatile over time. This means that when a firm seeks to refinance, the interest rates it must pay on that finance may be higher or lower than the rates it currently pays.

Figure 2. Bonds issued by Australian gas and electricity utilities

Issuer	Issue date	Maturity	Currency	Credit rating	Term of bond (yr)
Citipower	2003	2013	AUD	BBB+	10
Citipower	2007	2017	AUD	-	10
Citipower	2007	2017	AUD	-	10
ETSA	2005	2015	AUD	-	10
ETSA	2007	2019	AUD	-	12
Powercor	2005	2015	AUD	-	10
Powercor	2007	2021	AUD	-	14
Powercor	2007	2022	AUD	A-	15
SPI Aus	2011	2021	GBP	A-	10
SPI Aus	2010	2016	CHF	A-	6
SPI Aus	2010	2015	AUD	A-	5
SPI Elect & Gas	2003	2013	USD	A	10
SPI Elect & Gas	2004	2014	USD	A-	10
SPI Elect & Gas	2006	2016	USD	A-	10
SPI Elect & Gas	2008	2018	GBP	A-	10
SPI Elect & Gas	2010	2017	AUD	A-	7
SPI Elect & Gas	2010	2015	CHF	A-	5
SPI Elect & Gas	2010	2020	HKD	A-	10
SPI Elect & Gas	2011	2021	AUD	A	10
Jemena Ltd	1998	2018	USD	A-	20
Jemena Ltd	1998	2018	USD	A-	20
Jemena Ltd	2003	2015	USD	A-	12
Jemena Ltd	2003	2015	USD	A-	12
United Energy	2003	2016	USD	BBB	13
United Energy	2003	2016	USD	BBB	13
United Energy	2005	2014	AUD	BBB	9
Electranet	2000	2015	AUD	AA	15

Source: IPART (2012), Review of method for determining the WACC: Dealing with uncertainty and changing market conditions, December, Table 3.4.

One way that firms may seek to manage this risk is by raising long-term capital, which locks in interest rates for a long period of time. This makes sense particularly when financing the long-lived assets of utility networks. By raising capital over a long period, the firm is able to match the time profile of cash flows generated by the asset with its financing obligations. As Figure 2 shows, it is relatively common practice for Australian energy utilities to issue debt with a term of 10 years or more.

In normal economic times, the term structure of interest rates is generally positive. One explanation for a positive term structure is that long-term borrowing attracts a term premium, vis-à-vis short-term borrowing, to compensate investors for the opportunity costs of committing capital over a longer period of time. Therefore, by choosing to employ long-term finance, firms may be able to reduce refinancing risk and match better the time profiles of cash flows, but will typically pay a premium in the process.

2.1.11 Interest rate reset risk

Interest rate reset risk relates to the possibility that the costs of finance adopted by the regulator when determining allowed rates of return periodically do not match the actual cost of finance faced by the business. This risk may arise for a number of reasons:

- The regulator may have assumed a financing term that does not match the term over which the firm has actually financed. Differences between the rate of return allowed by the regulator and the firm's actual cost of capital might arise due to a mismatch of term premiums. This risk seems relatively small in the case of the AER. The AER has tended to use a term premium assumption of 10 years (in contrast to some other Australian regulators, who match the term assumption to the length of the regulatory period, typically five years). From Figure 2, it seems that many Australian energy companies raise 10-year (or close-to-10-year) debt.

- Estimation error. A firm's cost of capital cannot be observed directly. It can only be estimated using market data and the evidence available. Some parameters, such as the market risk premium, are inherently difficult to estimate. The models available for use in the estimation process all have known limitations; none will produce the 'right' answer. Further, the data available are often incomplete or imperfect. Given these challenges, the regulator's estimates may not match the firm's true cost of capital.

- Inefficient financing practices (e.g. failing to maintain a sound credit rating, or failing to take steps to manage risks effectively). Even if the regulator determines an appropriate allowed rate of return for the business, inefficient financing practices by the firm could drive a wedge between the allowed rate of return and the firm's cost of capital. However, it is reasonable to assume that the regulated businesses are rational profit-maximisers. As such, the incentives for the firms to adopt financing practices that drive up their cost of capital unnecessarily are weak.

2.1.12 Liquidity risk

Liquidity risk arises as a result of investor uncertainty over whether they will be able to trade a given asset at some point in the future. Sometimes it may be valuable for investors to be able to liquidate an asset at short notice due to an immediate need for cash, or at a given point in the future, in order to meet certain cash flow obligations.

Illiquidity may arise either because the firm's capital (equity and/or debt) is intrinsically not very marketable (i.e. traded thinly), or because of a fall in overall market liquidity, regardless of the marketability of individual assets. This was illustrated clearly during the global financial crisis (GFC). Following the collapse of Lehman Brothers in September 2008, and amidst fears of other bank failures, interbank lending fell sharply. This precipitated a general reduction in liquidity throughout the financial system. Many firms — including utilities that have historically been able to raise funds with relative ease — found long-term capital markets closed to them entirely, and were only able to raise short-term funding at a significant premium. This recent example illustrates that liquidity risk can arise for reasons well beyond the control of any individual firm.

The value that investors place on the liquidity of an asset, and the risk that it may not be realised, is usually reflected in the required return on that asset through an illiquidity premium. For instance, a number of studies (e.g. Blanco et al, 2005; Almeida and Philippon, 2007; Chen et al., 2007) suggest that a liquidity premium explains part of the observed spread on corporate bonds.[19] All else being equal, the more illiquid the asset, the higher the liquidity premium demanded by investors.

Regulators have also recognised this. For instance, in a recent consultation paper on its approach to WACC, IPART noted that:[20]

> The initial effect of the GFC on debt markets was an increase in debt margins (the difference between the risk free interest rate and the interest rate on corporate bonds), and corporations found it difficult to access debt markets due to liquidity constraints. While debt margins have subsequently decreased, they remain higher than pre-GFC levels in Australia and liquidity in debt markets remains a concern.

Here, IPART linked observed movements in corporate debt premiums during the GFC to changes in bond market liquidity.

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19 Blanco, R., Brennan, S., Marsh I. (2005), 'An empirical analysis of the dynamic relation between investment-grade bonds and credit default swaps', *Journal of Finance,* 60, 2255-2281; Almeida, H. and T. Philippon (2007) The Risk-adjusted Cost of Financial Distress, *Journal of Finance* 62(6), 2557–2586; Chen, L., Lesmond, D. A., Wei, J. (2007), Corporate yield spreads and bond liquidity', *Journal of Finance* 62(1), 119-149.

20 IPART (2012), *Review of method for determining the WACC: Dealing with uncertainty and changing market conditions*, December.

In its 2008 inquiry into regulated charges at Stansted Airport, the UK's Competition Commission decomposed the observed debt premium into a liquidity premium (60bps), a credit default premium (10bps to 35bps), and a systematic risk premium (45bps to 100bps).[21]

The liquidity of traded equity is often assessed by examining the stock's bid-ask spread (i.e. the difference between the highest price that a buyer is willing to pay for an asset and the lowest price for which a seller is willing to sell it). A wide bid-ask spread is an indication that the stock is not very liquid. In the UK, regulators have recognised that the equity in certain small networks, or private/closely-held networks, may be illiquid and have made allowances for this through the cost of capital (see Table 4).

2.1.13 Default risk

Default risk refers to the risk that the cash flows generated by the firm will be insufficient to cover its financial obligations. Firms that generate high cash flows relative to their financial obligations will generally have low default risk. Apart from the level of cash flows, default risk is also affected by the variability of the cash flows. The more stable the cash flows of the business, the lower will be the default risk attached to the firm.[22] All else being equal, the lower a firm's default risk, the lower will be the expected costs of financial distress, and the lower will be the firm's cost of debt.

Most assessments of default risk employ financial ratios that compare a firm's cash flows relative to its obligations. Credit rating agencies produce ratings that indicate the credit quality of firms and employ such cash flow coverage ratios as part of their analysis.

Rating agencies can influence investors' perceptions about the extent of default risk attached to a particular firm. Therefore, it is instructive to examine the factors that these agencies consider to be important in influencing the credit quality of utility businesses. According to the methodology applied by Moody's when rating regulated electric and gas utilities, it attaches weight quantitatively to the following four factors (see Figure 3).[23]

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21 Competition Commission (2008), *Stansted Airport Ltd Q5 price control review*, Appendix L, p.L35. The Competition Commission performed this decomposition in order to obtain an estimate of the debt beta.

22 Damodaran, A. (2001), *Corporate Finance: Theory and Practice*, 2nd edition, John Wiley.

23 Moody's Global Infrastructure Finance (2009), *Regulated Electric and Gas Networks*, August

Figure 3. Moody's methodology for rating regulated electric and gas utilities

Rating Factor/Sub-Factor Weighting			
Broad Rating Factors	**Broad Rating Factor Weighting**	**Rating Sub-Factor**	**Sub-Factor Weighting**
Regulatory Environment and Asset Ownership Model	40%	Stability and Predictability of Regulatory Regime	15.00%
		Asset Ownership Model	10.00%
		Cost and Investment Recovery	10.00%
		Revenue Risk	5.00%
Efficiency and Execution Risk	10%	Cost Efficiency	6.00%
		Scale and Complexity of Capital Programme	4.00%
Stability of Business Model and Financial Structure	10%	Ability and Willingness to Pursue Opportunistic Corporate Activity	3.33%
		Ability and Willingness to Increase Leverage	3.33%
		Targeted Proportion of Operating Profit Outside Core Regulated Activities	3.33%
Key Credit Metrics	40%	Adjusted ICR (or FFO Interest Cover)	15.00%
		Net Debt/RAV (or Fixed Assets)	15.00%
		FFO/Net Debt	5.00%
		RCF/Capex	5.00%
Total	100%		100.0%

Source: Moody's, August 2009

It is clear that the "Regulatory Environment and Asset Ownership Model" is a key element in the assessment as it makes up 40% of the overall assessment of the credit rating. Therefore a low score in this area (i.e. increased regulatory risk) would be expected to result in a poor overall credit rating.

The performance of the firm under key credit metrics (such as interest cover and cash flow cover ratios) also attracts a weighting of 40%. These ratios are affected directly by regulatory determinations on maximum allowed revenues. At least partly in recognition of this, several regulators in the UK (e.g. Ofwat, Ofgem, the Competition Commission, Northern Ireland Authority for Utility Regulation) as well as some regulators in Australia (e.g. IPART, ESC), undertake financeability assessments of the businesses they regulate. These financeability tests are based broadly on the key credit metrics that rating agencies employ.

Interestingly, factors such as cost efficiency, scale and complexity of the business's investment programme, stability of the business model and capital structure receive relatively low weight in Moody's assessments.

2.1.14 Financial counterparty risk

Businesses often enter into contracts with financial counterparties (e.g. banks, insurance firms) to manage a number of the risks discussed above. Examples of such contracts include insurance policies, swaps (e.g. to hedge against currency, interest rate or credit risks), and forwards and futures (e.g. to hedge the costs of inputs such as commodities). Financial counterparty risk refers to the risk that third parties fail to deliver on their obligations under these agreements.[24]

In normal economic times, financial counterparty risk may be relatively low. However, during financial crises, counterparty risk can increase substantially. For example, during the 2008 banking crisis, a sharp increase in counterparty risk occurred and nearly caused major institutions such as AIG to collapse.[25]

2.2 Features of a firm that may amplify or mitigate risks

In this section we consider four factors that are not risks per se, but may influence the scale of risks faced by firms, or the ability of firms to manage extant risks. These factors are: financial gearing; operational gearing; size; and the interlinked issues of ownership and the scope of commercial activities.[26]

2.2.1 Financial gearing

Financial gearing refers to the mix of debt and equity capital used by businesses to finance their activities. Finance theory tells us that financial gearing affects the risks borne by equity and debt holders.

- **Effect on the cost of equity.** Equity holders are residual claimants to the cash flows of the firm, which means equity holders are repaid only once debt holders have been remunerated fully.[27] This means that as businesses increase their financial gearing, the likelihood of equity holders being repaid falls, all else being equal. In other words, the financial risks borne by equity holders increases with financial gearing.

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24 In this sense, financial counterparty risk is analogous to supplier risk.

25 Many financial institutions lend to one another and insure themselves against losses on these loans by purchasing credit default swaps (CDS). In 2008 AIG was the largest seller of CDS in the world. In September 2008 Lehman Brothers collapsed, which resulted in firms with insurance against a Lehman default making CDS claims. The uncertainty caused by Lehman's collapse about the stability of other banks raised concerns about AIG's ability to meet all its CDS obligations should further defaults occur. This in turn resulted in large collateral calls being made on AIG by its counterparties, which eventually became unsustainable and nearly caused AIG itself to default. Stulz, R. (2010), 'Credit Default Swaps and the Credit Crisis', *Journal of Economic Perspectives* 24(1), 73-92.

26 Financial gearing and operational gearing are sometimes described loosely as 'risks'. Strictly speaking, these are not risks; these are factors that influence the level of financial and business risks (respectively) that a firm may be exposed to.

27 Firms always pay their interest obligations before they pay dividends, and in the event of bankruptcy, debt investors are always repaid before equity holders.

- **Effect on the cost of debt.** Assuming all else remains equal, as financial gearing increases, so too does the risk of default. At a certain level of financial gearing, the firm may be viewed by investors as materially less creditworthy (and this might be reflected in a lower credit rating). This in turn is likely to push up the firm's cost of borrowing through an increase in the default risk premium. The amount of financial gearing that a firm is able to bear depends on the total amount of risk within the firm (i.e. business risk and financial risk).

What is the impact of higher financial gearing on the WACC? According to a theory developed by Modigliani and Miller (M&M), the WACC should invariant to changes in gearing.[28] M&M's proposition says that any benefit gained by substituting more expensive equity capital for relatively cheaper debt capital should be offset exactly by the increase in the cost of equity (since equity becomes riskier with more borrowing). The reason that the two effects offset each other exactly is because the underlying risk of the assets does not change as gearing changes; risk is simply been redistributed between debt holders and equity holders.

However, the trade-off theory suggests that when corporate taxes and the costs of financial distress are taken into account, WACC does vary with gearing. The theory recognises that firms enjoy increasing tax advantages by borrowing (since the value of the interest tax shield increases with gearing). However, as noted above, as gearing increases, so too does the probability of default and, therefore, the expected costs associated with financial distress. When this trade-off is recognised, the WACC can vary with gearing, even within a M&M framework (Damodaran, 2001, chapter 18).

2.2.2 Operational gearing

Operational gearing refers to the mix of fixed and variable costs within a business. Firms with a high proportion of fixed costs, relative to variable costs, are said to have high operational gearing. Operational gearing increases the non-diversifiable risk of a business.[29] A company that has a high proportion of fixed costs must continue to meet those costs regardless of whether the firm's revenues are high or low. This means that the firms with high operational gearing will have high variability in operating income. In contrast, firms with a high proportion of variable costs will find that their costs and revenues fluctuate in line with output, which means operating income will tend to be less variable.

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28 Modigliani, F., Miller, M. (1958), 'The cost of capital, corporation finance and the theory of investment', *American Economic Review* 48, 261-297.

29 See, for example, McKenzie, M., Partington, G. (2012), *Estimation of the equity beta (conceptual and econometric issues) for a gas regulatory process in 2012 – A report to the AER*, April.

The degree of operational gearing of a business is usually determined by the nature of the business. For instance, capital intensive businesses (such as network utilities and infrastructure firms) have a high proportion of fixed costs and therefore tend to be more operationally geared than low capital intensity firms. Network businesses particularly cannot alter their capital intensity since physical capital is so central to the activities undertaken by these firms.

2.2.3 Size

Evidence that size affects the cost of capital

There is some empirical evidence that the size of a business influences its cost of capital. For example, Brealey et al. (2013) report that the average annual difference in the cumulative returns of small-firm stocks and large-firm stocks in the US since 1926 has been 3.6%.[30] In other words, on average and over a long period of time, small firms in the US appear to have delivered higher returns to investors than large firms.

The Duff & Phelps Risk Premium Study, which is updated annually, finds similar evidence. Using US data from 1963, and correcting for 'delisting bias', the study tests the relationship between realised equity risk premiums and eight different measures of firm size.[31] By whatever measure of size used, a clear inverse relationship between size and historical risk premiums is found.[32]

The evidence for a small company premium is not isolated to the US. As Damodaran (2013) notes,[33] studies have found evidence of average small company premiums in the UK (7% between 1955 and 1984),[34] France (8.8%) and Germany (3.3%),[35] and Japan (5.1% between 1971 and 1988).[36] Dimson, Marsh and Staunton (2013) examine realised returns in 19 economies using data from

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30 Brealey, R. A., Myers, S. C., Allen, F. (2013), *Principles of corporate finance*, 11th edition, McGraw-Hill: New York.

31 The measures of size are: market value of common equity; book value of common equity; five-year average net income before extraordinary items for the previous five fiscal years; market value of invested capital; total assets; five-year average EBITDA; sales and number of employees.

32 Pratt, S. P., Grabowski, R. J. (2010), *Cost of capital: Applications and examples*, 4th edition, John-Wiley: New Jersey.

33 Damodaran, A. (2013), 'Equity risk premiums (ERP): Determinants, estimation and implications – the 2013 edition', *Stern School of Business working paper*.

34 Dimson, E., Marsh, P. R. (1986), 'Event studies and the size effect: The case of UK Press Recommendations', *Journal of Financial Economics* 17, 113-142.

35 Bergstrom, G. L., Frashure, R. D., Chisholm, J.R. (1991), 'The gains from international small-company diversification in global portfolios: Quantitative strategies for maximum performance', eds. R.Z. Aliber and B.R. Bruce, *Business One Irwin*: Homewood.

36 Chan, L.K., Hamao, Y., Lakonishok, J. (1991), 'Fundamentals and stock returns in Japan', *Journal of Finance* 46, 1739-1789.

1900 and find that small companies have historically outperformed large companies in all but two countries studied, Denmark and Norway.[37]

One possible explanation for a size effect, if it exists, may be pure chance — an artefact of sampling, or simply spurious trends observed in the data. However, this seems unlikely given that the phenomenon appears to persist over a long period of time, and arises in many countries.

Another possible explanation is that investors in small companies consider these intrinsically riskier than large companies and therefore expect a higher return when investing in small stocks. A counterargument to this view is that what is actually observed are realised returns rather than investors' ex ante expectations, and investors' expectations may not in fact be that small companies will yield higher returns than large companies. As Brealey et al (2013) note:

> Actual stock returns reflect expectations, but they also embody lots of "noise" – the steady flow of surprises that conceal whether on average investors have received the returns they expected.

The evidence on small company premia cited above is based on data over relatively long periods of time. However, other studies over more recent periods have suggested that small company premia are much smaller or non-existent (e.g. Cochrane, 1999; Campbell, 2000; and Horowitz et al. 2000).[38] Brealey et al. (2013) have suggested that the recent apparent disappearance of the size premium in some countries might be the result researchers identifying and publicising its existence. This might have caused the premium to be arbitraged away (e.g. through the establishment of small cap funds to exploit these opportunities).

Australian evidence for a size premium

A number of studies have tested the Fama and French three factor model using Australian data. Table 2 summarises the evidence on the size premium from a selection of these studies.

Table 2: Summary of Australian evidence on the Fama-French size premium

Study	Period	Average size premium	Statistical significance
Halliwell et al. (1999)	1980-1991	6% p.a.	Not stated
Faff (2001)	1991-1999	-3.7% p.a.	Not stated

37 Dimson, E., Marsh, P., Staunton, M. (2013), *Credit Suisse Global Investment Returns Sourcebook* 2013.

38 Cochrane, J. H. (1999), 'Portfolio advice for a multifactor world', *Economic Perspectives, Federal Reserve Bank of Chicago* 23(3), 59-78; Campbell, J. Y. (2000), 'Asset pricing at the millenium', *Journal of Finance* 55(4), 1515-67; Horowitz, J. L., Loughran, T., Savin, N. E. (2000), 'Three analyses of the firm size premium', *Journal of Empirical Finance* 7, 143-153. .

Faff (2004)	1996-1999	-6.1% p.a.	Not stated
Chan and Faff (2005)	1990-1998	23.3% p.a.	Yes
Gharghori et al. (2007)	1996-2004	18.6% p.a.	Yes
Kassimatis (2008)	1993-2005	11.5% p.a.	Yes
Brailsford et al. (2012)	1982-2006	c. -2.6% p.a.	No

Sources: Halliwell, J., Heaney, R., Sawicki, J. (1999), 'Size and book to market effects in Australian share markets: a time series analysis, Accounting Research Journal 21(2), 122-137; Faff, R. (2001), 'An examination of the Fama and French three-factor model using commercially available factors', Australian Journal of Management 26(1), 1-17; Faff, R. (2004), 'A simple test of the Fama and French model using daily data: Australian evidence', Applied Financial Economics 14, 83-92; Chan, H. W., Faff, R. W. (2005), 'Asset pricing and the illiquidity premium', The Financial Review 40, 429-458; Garghori, P., Chan, H., Faff, R. (2007), 'Are the Fama-French factors proxying default risk?', Australian Journal of Management 32(2), 223-249; Kassimatis, K. (2008), 'Size, book to market and momentum effects in the Australian stock market', Australian Journal of Management 33(1), 145-168; Brailsford, T., Gaunt, C., O'Brien, M. A. (2012), 'Size and book-to-market factors in Australia', Australian Journal of Management (online), 1-22

According to these studies, the evidence for a size premium in Australia is mixed:

- Four studies report large positive size premiums; three of these studies (Halliwell et al., 1999; Chan and Faff, 2005; and Gharghori et al., 2007) present evidence of statistical significance.
- Three studies report negative size premiums; of these, one study (Brailsford et al., 2012) could not reject that the negative premium was statistically different from zero, whilst the two remaining studies (both by Faff alone) did not present any evidence on the statistical robustness of the measured premium.

Of all the studies, the one by Brailsford et al. (2012), which could find no statistical evidence for a premium, was the most comprehensive in terms of data coverage (years and the number of companies canvassed).

CAPM evidence

The theory of the CAPM suggests that company size should not matter because systematic risk is the only driver of differences in the returns that investors expect from different assets. However, there is some CAPM-based evidence that size might influence the cost of capital.

The Ibbotson SBBI Valuation Yearbook published by Morningstar presents evidence on the betas and historical risk premiums (since 1926) for US companies. Ibbotson divides firms listed on the NYSE into size deciles, where size is measured by the aggregate market value of common equity. Table 3 presents Ibbotson beta estimates, realised risk premiums and the premiums predicted by the CAPM (i.e. beta multiplied by the MRP) published in the 2009 yearbook, which are reproduced in Pratt and Grabowski (2010).

The Ibbotson analysis indentifies a negative relationship between company size and the CAPM beta, and a negative relationship between size and realised risk premiums. Furthermore, the CAPM-predicted risk premiums were found to be lower than realised returns for all but the largest firms. Ibbotson repeats this analysis annually and has found very consistent results over time.

Table 3: Betas and risk premiums for US firms by size

Decile	Beta	Realised risk premium	CAPM risk premium
1 – Largest	0.91	5.56%	5.91%
2	1.03	7.31%	6.69%
3	1.10	7.87%	7.13%
4	1.12	8.25%	7.28%
5	1.16	9.03%	7.49%
6	1.18	9.28%	7.65%
7	1.24	9.65%	8.03%
8	1.30	10.76%	8.41%
9	1.35	11.42%	8.71%
10 – smallest	1.41	14.93%	9.12%
Mid-cap (deciles 3-5)	1.12	8.18%	7.24%
Low-cap (deciles 6-8)	1.22	9.66%	7.92%
Micro-cap (deciles 9-10)	1.36	12.52%	8.79%

Adapted from: Pratt, S. P., Grabowski, R. J. (2010), Cost of capital: Applications and examples, 4th edition, John-Wiley: New Jersey, Exhibit 13.1

Potential reasons for a size premium

The survey of the literature above suggests that there is some empirical evidence for a negative relationship between firm size and the cost of capital. However, some studies find evidence for a negative premium, and some find no evidence at all for a size premium.

Even if the cost of capital is related negatively to business size, there is no compelling extant theory that explains such a relationship. This makes it difficult to judge to what extent the relationship is applicable to specific sectors, such as regulated utilities. There are hypotheses that postulate why small companies might have a higher cost of capital than large firms, but to our knowledge these have not been proven either way. Some possible explanations include the following:

- Small companies tend to have more concentrated ownership structures, which may imply that the investors in these companies are themselves not well-diversified.[39] This does not seem a relevant consideration for the types of networks regulated by the AER.

- The asymmetries of information that potential investors face with small firms may be more severe than with large firms. This may cause investors to view small firms as more difficult to value and therefore more risky. This issue seems less relevant for regulated businesses since the regulatory process generally facilitates reasonably good disclosure of information about firms, even relatively small ones, which might otherwise have remained private.

- Small companies may not be as well-resourced to weather external economic shocks as well as large companies, which may make their returns inherently riskier. This could potentially be a valid issue for small regulated businesses. In relation to this issue, financeability and scenario testing of the sort undertaken by UK regulators, and some Australian state-level regulators, could be used to assess if the networks are likely to be sound financially over the regulatory period, and how risky the market may view the firms.[40]

- Securities issued by small companies tend to be more illiquid than securities issued by large firms, so much of the small company premium may really reflect a premium for illiquidity. The illiquidity of small stocks may arise in part if small companies find access to capital markets more costly than large companies. This could potentially be a relevant concern with respect to small regulated businesses.

Regulatory allowances for small company premia – UK evidence

Table 4 summarises a number of the prominent instances in the UK where regulators have made explicit adjustments to the cost of capital for company size.

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39 In small firms with concentrated ownership structures, the investors may have much of their wealth invested in the business, and may therefore find little of the risk they are exposed to diversifiable. This is analogous to the situation faced by owners of private, closely-held firms who might enjoy few diversification opportunities (Damodaran, 2001, p.233).

40 Although these tests are typically conducted on a notional basis (e.g. assuming a notional capital structure), there is no reason why these tests could not also be calibrated to take into account the circumstances (e.g. scale) of individual firms or groups of firms.

Table 4. Small company premium allowances made by UK regulators

Determination	Reasons given for premium	Allowance made in the WACC
Competition Commission (Bristol Water, 2010)	Small water companies tend to have higher operational gearing than large water companies, and therefore higher systematic risk Small water companies may be more illiquid than large water companies	Increased asset beta by 18% to reflect the higher operational gearing of Bristol Water (a water only company) than larger, water and sewerage companies.
Ofwat (water only companies, 2009)	Access to debt finance is more limited for small water companies	0.1% to 0.4% premium on the cost of debt, over and above allowances for debt raising costs (assumed to be 0.2%)
Ofwat (2004)	The equity of small (water only) companies is relatively illiquid Small water companies pay a premium to access debt markets Transaction costs associated with raising debt and equity	0.3% - 0.9% premium on the post-tax WACC
Ofgem (independent gas transporters, 2002)	Higher transaction costs from dealing in the shares of smaller companies, where market liquidity tends to be relatively low "Where an IGT is financially and operationally ring-fenced from a parent company a small company premium could apply to the cost of equity. Where IGTs continue to operate without such restrictions as a part of a large company it is not clear that it would be appropriate to apply such a premium."	0.8% premium on post-tax cost of equity
Competition Commission (water inquiries, 2000)	Impact of lower trading liquidity on cost of equity	1% premium on post-tax cost of equity
Ofwat (1999)	More limited access to capital markets "These premia apply to all independent water only companies. Those which are subsidiaries of large groups have accepted licence amendments to guarantee their independence. These licence amendments ensure that such companies operate on an arm's length basis from other group companies, including their parent company and hence can be considered as small, independent companies."	0.4% - 0.75% premium on post-tax WACC

Sources: Competition Commission (2010), Bristol Water Plc A reference under section 12(3)(a) of the Water Industry Act 1991 – Report; Ofwat (2009), Future water and sewerage charges 2010-15: Final determinations; Ofwat (2004), Future water and sewerage charges 2005-10 – Final determinations; Ofgem (2002), Independent Gas Transporter Charges and Cost of Capital Consultation; Competition Commission (2000), Mid Kent Water Plc: A report on the references under sections 12 and 14 of the Water Industry Act 1991; Competition Commission (2000), Sutton and East Surrey Water Plc: A report on the references under sections 12 and 14 of the Water Industry Act 1991; Ofwat (1999), Future water and sewerage charges 2000-05 – Final determinations

Almost all these instances relate to the regulated water businesses, and more than one regulator (i.e. Ofwat as well as the Competition Commission) has made such allowances for companies in that sector. It is worth noting that Ofwat had a policy of restricting mergers within the industry, in part to facilitate its ability to conduct benchmarking exercises. Regulatory barriers of this kind might provide some justification for the for the small company allowances made by Ofwat.

Small company premiums have been allowed only very rarely in relation to regulated energy networks because, on the whole, these networks are much larger than some of the regulated water companies. When Ofgem did make such an allowance, it did so only if there were barriers imposed by regulation (i.e. ring-fencing provisions) on the business benefitting from the benefits of being funded through a parent.

The key reasons that UK regulators have given for differentiating the cost of capital between small companies and large companies have been:

- The relative illiquidity of capital in small firms, which might be the result of high transaction costs; and
- An acceptance that the small companies in question happened to have higher operational gearing than larger counterparts.

On the first of these reasons, some of the smaller energy networks have submitted to the AER that they find capital markets difficult or more costly to access than larger networks. We have been advised by the AER that it currently provides allowances to firms outside the cost of capital for debt issuance costs, and that the AER's per-unit allowance for these costs does scale with RAB size (i.e. on a per-dollar-raised basis, the debt raising costs increase as the value of RAB falls). In principle, this could deal with illiquidity concerns that surround small energy networks, provided that the allowances are calibrated appropriately. McKenzie and Partington (2013) argue that allowances for transaction costs, if made at all, should be provided through the regulatory cash flows rather than through the allowed rate of return.

The second point on the operational gearing of businesses was dealt with above.

Does firm size affect ability to hedge financial risks?

A quite separate issue, which relates to the how readily businesses of different scale are able to manage and hedge financial risks, has been raised recently by some stakeholders through submissions to the AER and the AEMC. For instance, in its recent rule change in relation to the economic regulation of network service providers, the AEMC noted that:[41]

> A case was made, for example by the QTC, New South Wales Treasury Corporation (NSW T-Corp) and Ausgrid, that the current regulatory position of calculating interest rates on debt over a 20 to 40 day period encourages risk management behaviour in service providers that, in general, would not likely occur in the absence of such regulation. They argued that it also comparatively disadvantages large service providers whose ability to hedge large volumes of interest rate risk over such a short period is severely limited by the size and liquidity of the relevant markets.

In a recent submission to the AER, the ENA stated that:[42]

> The strategy of staggered debt issuances with a swap overlay (i.e., the strategy that matches clause 6.5.2(j)(3)) is available to some NSPs but not all NSPs – depending on the circumstances and characteristics of the NSP in question. The constraining factor in this regard is the depth of the interest rate swaps market. This is a function both of the NSP's own size on what other businesses (energy NSP or otherwise) may be seeking to access the swap market at the same time. Whereas small to mid-sized NSPs may usually have sufficient access to swaps, the AEMC accepted that it is unlikely that very large NSPs could access the volume of swaps that they would require.

Finally, the QTC submitted to the AER:[43]

> Under the current approach, aligning the actual and benchmark debt risk premium component of the cost of debt requires an NSP's debt to fully mature during each 10 to 40 day averaging period. In practice, NSPs do not adopt this type of maturity profile because doing so would expose them to an unacceptably high level of refinancing risk.
>
> A similar problem arises for some NSPs when seeking to align the base interest rate component of the cost of debt as it is currently determined. For NSPs with large debt portfolios, attempting to transact a large volume of interest rate swaps with the same tenor over 10 to 40 consecutive days will create exposures to new risks, such as opportunistic pricing by other market participants and the risk of incurring large transaction costs due to insufficient market liquidity.
>
> As there is no way of reliably estimating the potential impact of these risks, it is prudent and efficient practice for large NSPs to progressively re-price their base interest rate over a much longer period of time.

These stakeholders have raised three key issues for consideration:

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41 AEMC (2012), *Rule determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November, p.74.

42 ENA (2013), *Response to the AER rate of return guidelines – issues paper*, February, p.30.

43 QTC (2013), *Rate of return guidelines issues paper – submission to the Australian Energy Regulators*, February, p.8.

- Large networks typically have a large quantity of debt that needs to be refinanced. Similarly, the state treasury corporations usually need to manage large quantities of debt for a number of businesses. It is prudent and efficient to stagger this refinancing over a period of time, to minimise refinancing risks, rather than roll-over large quantities of debt all at once.

- There is insufficient liquidity in interest rate swap (IRS) markets to allow the networks or state corporations to hedge large quantities of debt within a relatively short period of time.

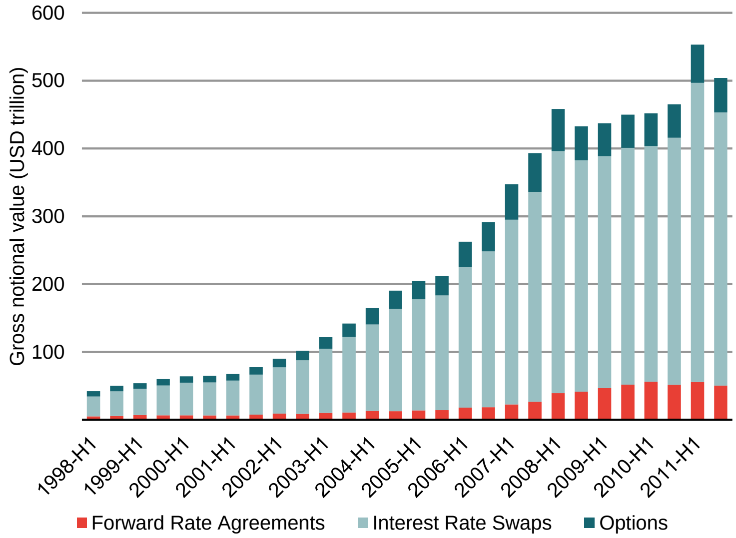
- Attempting to lock-in rates using IRSs over a relatively short period of time exposes the networks to the risk of manipulation of swap rates by financial market participants aware of the networks' needs to hedge refinancing risks.

The first of these points seems reasonable to us. In relation to the second and third points, we acknowledge that these may be genuine issues that the businesses face, and further engagement between the AER and the networks about these concerns would be ideal. However, we make the following observations.

On the point about the market depth, we note that IRS markets are the largest and most liquid financial markets in the world, dwarfing the markets for bonds or shares. According to the Bank of International Settlements (BIS), at the end of 2012 the gross notional value of the global IRS market was close to US$370 trillion.[44] As Figure 4 shows, IRSs represent the majority of all over-the-counter (OTC) interest rate derivatives traded globally. BIS (2013) statistics indicate that at the end of 2012 IRS made up over 69% of all OTC derivatives traded globally, by gross market value.

44 BIS (2013), *Statistical release: OTC derivatives statistics at end-December 2012*, May.

Figure 4. IRS as a share of all OTC interest rate derivatives



Source: Bank for International Settlements

According to the International Swaps and Derivatives Association (ISDA), between 1 January 2013 and 26 March 2013, the notional value of Australian dollar IRSs executed was in excess of $US420 billion — the fifth-ranked currency by notional value (Figure 5). Over this period, 4,741 AUD IRS trades were executed.

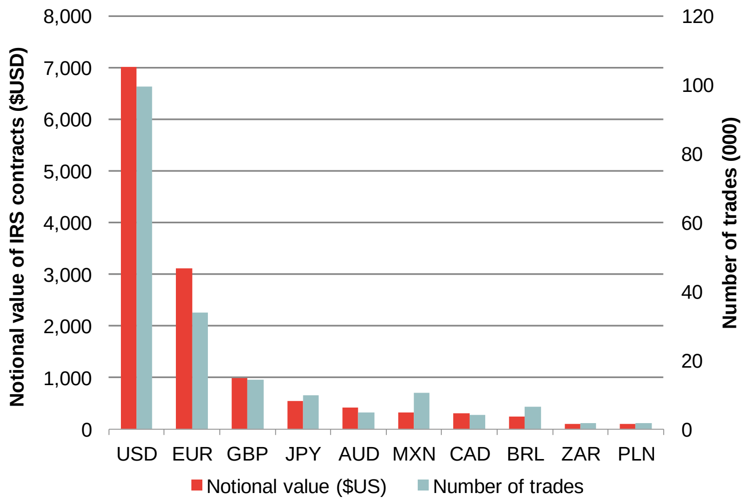
Although still considerably smaller than the value and volume of US or Euro currency swaps executed over the same period, the figures are not trivially small. However, it is possible that much of this activity may represent trades by Australian financial institutions, such as banks.

In a recent submission to the government on reforms to the retail bond market, the Australian Financial Markets Association (AFMA) stated that:[45]

> Australia has the advantage of well-functioning liquid derivatives markets which enable hedging and risk management, in particular via the currency and interest rate swaps market.

45 AFMA (2012), *Submission to the Australian Government Discussion Paper: Development of the retail corporate bond market – streamlining disclosure and liability requirements*, February. AFMA represents over 130 members, including Australian and international banks, leading brokers, securities companies, state government treasury corporations, fund managers, traders in electricity derivatives, and other specialised markets and industry service providers.

Figure 5. IRS trades by currency between 1 January 2013 and 26 March 2013



Source: ISDA, Rates SDR Liquidity Data (January - March 2013) – Data update, 2 April 2013

On the third point, which relates to the scope for manipulation of IRS rates, we note that the vast majority of IRS trades are executed bilaterally, on an OTC basis, between the end-user and a dealer.[46] It is possible that the dealers might attempt to shade their quotes opportunistically to attempt to exploit the networks' need to swap their rates over a specific period of time. However, the OTC nature of the IRS market means that dealers submit their quotes to customers blind to what other dealers may be quoting at the time, which may discourage opportunistic behaviour by dealers to manipulate swap rates.

In summary, we agree with the submitters that it is prudent and efficient to stagger the refinancing of large tranches of debt over a long period of time rather than refinancing all existing debt at once. Refinancing all debt simultaneously would probably be infeasible for large companies. However, it does not seem to us that periodic resetting of allowed returns by a regulator should compel businesses to refinance all their debt all at once. The important question is whether the businesses are able to hedge interest rate risk and refinancing risk effectively. It is not obvious to us that large networks are necessarily disadvantaged in terms of their ability to manage these risks using instruments such as IRSs.

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46 These trades often occur over multi-dealer electronic platforms such as Bloomberg's Fixed Income Trading platform (FIT) or Tradeweb's Dealerweb platform. These systems allow buy-side customers to seek live, competitive quotes from a large number of dealers, which can be compared and executed by the customer.

Risks that may be relevant to regulated networks in Australia

The AER has advised us that it intends to engage further with stakeholders to understand their concerns in more detail. We think that would be a helpful step to take. We also recommend that the AER engage with dealers of IRSs (i.e. banks) to understand how liquid the IRS market in Australia is.

2.2.4 Ownership and scope of activities

It is a well accepted principle in financial economics that the cost of capital of a particular project depends on the risk characteristics of that project and not the overall cost of capital of the firm that owns the rights to that project. For example, when considering a firm that is contemplating an expansion of its activities by undertaking some new projects, Brealey et al. (2013, p.219) state that:

> The company cost of capital is *not* the correct discount rate if the new projects are more or less risky than the firm's existing business. Each project should in principle be evaluated at its *own* opportunity cost of capital. This is a clear implication of the value-additivity principle ... If the present value of an asset depended on the identity of the company that bought it, present values would *not* add up, and we know they do. (Emphasis in the original.)

Damodaran (2001, p.230) states:

> Can we use the costs of equity and capital that we have estimated for the firms for these [individual] projects? In some cases we can but only if all investments made by a firm are similar in terms of their risk exposure.

The implication for regulators is that when determining the cost of capital for regulated businesses that belong to a wider group, the regulator should begin by considering if the risks associated with the regulated activities of interest are similar to those of the rest of the group. If there is evidence that the risks differ materially, then the regulator ought to assess the cost of capital for the regulated business on the basis that it is a standalone entity, regardless of its place within a wider group.

This is essentially the approach that regulators in the UK have adopted. As in Australia, the scope of commercial activities that are regulated in the UK is defined by licences issued to regulated businesses.[47] This means that it is the services defined in the licences, rather than the companies undertaking the activities, that are the subject of regulatory control. Under this approach, UK regulators generally seek to determine the cost of capital of the regulated activities rather than the cost of capital of the company delivering those services. In this regard, two prominent examples are worth noting:

- **Telecommunications.** In 2006, following a strategic review undertaken by the UK's communications regulator Ofcom, British Telecom (BT) was

47 This is true of a number of sectors, including energy, water and airports.

functionally-separated from its infrastructure business now known as Openreach. Openreach came under a new regulatory framework, which implemented local-loop unbundling and facilitated equal third-party access to BT's local network. Openreach remains a wholly-owned subsidiary of BT. When regulating Openreach's activities, Ofcom concluded that it was appropriate to disaggregate BT's overall WACC into a 'copper access' (i.e. an Openreach) WACC, and a WACC for the 'rest of BT'. It did so because it considered that Openreach is exposed to significantly less risk than the rest of BT, which is engaged primarily in 'information and communications technology', and using an overall BT WACC would therefore overstate the risks faced by Openreach.[48]

- **Airports.** In the UK three London airports (Heathrow, Gatwick and Stansted), all owned by the British Airports Authority (BAA), are designated as subject to price controls by the Civil Aviation Authority (CAA). As part of the quinquennial price review process, the CAA must refer the matter to the UK Competition Commission, which makes recommendations to the CAA on maximum charges at these three airports. In its 2007 and 2008 determinations, the Competition Commission decomposed BAA's WACC into separate WACCs for each of the three airports on the basis that they each have distinct risk profiles.[49]

There may be situations in which a regulated network relies on a parent or the wider group to raise its capital because that is more cost efficient than raising the capital itself. For instance:

- There may be scale economies associated with the costs of issuing debt centrally. If these issuance costs are largely fixed, they may be spread over a number of divisions/subsidiaries.

- A group or large parent may be able to access certain capital markets with minimum issuance size requirements, which might otherwise be out of reach of a small individual subsidiary. This would allow the subsidiary to access a wider investor base than it would on its own.

- Finally, by pooling its risks across a number of subsidiaries and projects, a group may be able to achieve some internal diversification, thus lowering its default risk and reducing its cost of borrowing.

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48 Ofcom (2005), *Ofcom's approach to risk in the assessment of the cost of capital – final statement*, August.

49 Competition Commission (2007), *BAA Ltd - A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd)*, September; and Competition Commission (2008), *Stansted Airport Ltd - Q5 price control review*, October.

Risks that may be relevant to regulated networks in Australia

Under such circumstances, viewing the regulated network strictly as a standalone entity may lead the regulator to determine an allowed rate of return in excess of the business's efficient funding costs. By treating the business as a standalone, the regulator might even apply a small company premium, or allow larger capital issuance costs, than would be the case if the synergies associated with group ownership were recognised. We do not think this would be sensible.

As Table 4 showed, UK regulators such as Ofgem and Ofwat have countenanced higher funding costs for subsidiaries that are effectively made standalone, in a financial and operational sense, through ring-fencing provisions.[50] However, such allowances have not been permitted when the absence of ring-fencing provisions has meant that subsidiaries might reap funding benefits that arise through group ownership.

2.3 Quantification of risks

The AER has sought advice from us on how to measure the risks that should be compensated through the WACC. When answering this question, it is important to make two important distinctions.

The first is the distinction between individual sources of risk and the *effect* of those risks on the firm. Section 2.1 discussed in detail the various risks that could be relevant to regulated network businesses. The observable volatility in the cash flows or returns of a firm is the result of these risks acting collectively on the firm. Different firms have different sensitivities to the various individual risks identified above, depending on the circumstances of those firms. Hence, the volatility of one firm's cash flows can differ from the volatility of another's.

The second distinction is between the concept of total risk and the risks that are actually priced into expected returns by investors. Total risk is the overall volatility of a firm's cash flows/returns. It may be decomposed into two parts:

$$\text{Total risk} = \text{Diversifiable risk} + \text{Non-diversifiable risk}$$

As explained by McKenzie and Partington (2013), the rate of return should provide compensation for only non-diversifiable risk (which they refer to generally as 'covariance risk') because in competitive and efficient capital markets investors will not price diversifiable risks.

In practice, the measurement of non-diversifiable risk can be challenging, in part because the definition of non-diversifiable risk varies depending on the asset

50 In the UK and US regulators have required regulated utilities to be ring-fenced from parent companies in order to protect the essential services provided by the utilities in the event that the parent experiences financial distress. Such provisions proved valuable in the cases of Wessex Water in the UK and Portland General Electric Company in the US, both of which were owned by Enron prior to its collapse. When Enron failed, the ring-fences protected the subsidiaries from contagion.

pricing model used. Hence, the practical task of measuring non-diversifiable risk requires choices to be made about the most suitable model(s) for the task. The question of which model the AER should be using is beyond the scope of our report. However, in Chapter 6 we present a conceptual framework that the AER could use to estimate non-diversifiable risk that can accommodate a range of possible models.

It is possible to measure (in some cases, with difficulty) the individual risks introduced in 2.1. Conceptually, this can be done by modelling, using historic data, the dispersion or deviation of possible outcomes, for a given risk factor (e.g. demand, input prices, inflation, the entry of a rival, bankruptcy, etc.), about the expected (mean) outcome. However, the measurement of *individual* risks does not help to answer the key question posed by the AER: how should the risks to be compensated through the WACC be measured?

This is because the quantification of individual risks, as described above, provides no concrete information on how these risks contribute towards the non-diversifiable risks that are actually priced by investors. In order to understand that, it is necessary to apply empirically one or more of the asset pricing models surveyed in McKenzie and Partington (2013). Most of these models:

- Take as given that the combined effect of the various risks that firms face are reflected in their cash flows/returns. Just as price in a market for goods and services conveys information about the various factors that buyers and sellers take into account (e.g. tastes and preferences, scarcity, availability of substitutes and complements, etc.) when trading, cash flows/returns convey information about the risks that affect a firm. Just as the availability of price information obviates the need to model hedonically every factor that affects the demand for, and supply of, goods and services, information on cash flows/returns obviates the need to model the individual risks that impact on firms.

- Estimate the sensitivity of those cash flows/returns to one or more wider **factors**. Factors are economic variables that might be correlated with company cash flows/returns.[51] The estimated correlation coefficient between a factor and cash flows/returns provides an estimate of the covariance risk that should be compensated through the cost of capital.

Therefore, the key issue is whether the AER has a sound framework for estimating covariance risk. In Chapter 6 we set out some practical recommendations in this regard.

51 The Sharpe-Lintner and Black versions of the CAPM have just one factor, the 'market factor'. Merton's CAPM and the Fama and French model incorporate multiple factors.

2.4 Circumstances in which certain risks should not be compensated

The discussion above has identified a large number of risk categories that regulated businesses might potentially be exposed to. However, it does not follow that businesses should be compensated for all risks that they bear. This so for two reasons:

- **Managerial action can mitigate risks.** There are many actions that the businesses can and should take in order to limit their exposure to risks. It would be inappropriate for the regulator to grant businesses allowances for failing to manage risks that ought to be within their control (e.g. failure to hedge risks appropriately through financial markets, or contracting arrangements with suppliers and customers). Doing so would be inconsistent with the principles of incentive regulation. Section 3.1 discusses some of the ways in which businesses can manage their risks.

- **Excessive risk-taking.** Behaviour consistent with excessive risk-taking should not be rewarded. An example of excessive risk-taking might be if the business were to increase its financial gearing to the point that it faces a high probability of default and financial distress. Even if default does not become imminent, an increase in gearing may raise the firm's borrowing costs beyond efficient levels. The desire to avoid rewarding firms for borrowing excessively, thereby increasing financial risk, is one important reason that regulators assume a notional, rather than actual, level of financial gearing when determining the WACC. It is for similar reasons that regulators determine the cost of debt based on a benchmark credit rating, which might differ from the firms' actual rating.

3 Mechanisms for managing and allocating risk

In this chapter we assess how the risks discussed in Chapter 2 might potentially be managed. In particular, we focus on actions that regulated businesses could take, and we also consider regulatory arrangements that can facilitate the sharing of risks between businesses and customers.

3.1 Managerial action

3.1.1 Hedging instruments and conventional insurance

Businesses can manage a wide range of business and financial risks using hedging instruments and conventional insurance products.

Hedging instruments

Businesses can use financial derivatives to hedge a wide range of risks, including input price risk, inflation risk, currency risk and interest rate/refinancing risk. Derivatives are financial assets whose payoff depends on the value of another asset or economic variable, which is referred to as the **underlying**. Firms can purchase derivatives (e.g. swaps, forward and futures contracts, and options) to hedge risk associated with the underlying.

- **Swaps** allow firms to exchange one stream of cash flows for another. For example, interest rate swaps are often used to exchange a future stream of variable interest payments for a set of fixed interest payments and can be used to hedge interest rate risk. Currency swaps allow the exchange of one currency for another and can be used to hedge exchange rate risk.

- **Forward contracts** allow firms to fix a purchase (or sale) price for a commodity (e.g. a production input) or currency at some point in the future. Virtually all forward contracts are bespoke over-the-counter (OTC) products. This means they can usually be customised to suit the hedging requirements of the purchaser of the forward.

- **Futures contracts** are similar to forward contracts in the sense that they allow firms to lock in the price of a good for some time in the future. However, futures are standardised instruments that permit little customisation to occur. This allows them to be traded easily over exchanges.

- **Options** give the holder the right, but not obligation, to buy or sell a particular type of asset. Firms can use options to protect against downside risk while preserving upside potential. Options exist to manage, for example, exchange rate risk, input price (i.e. commodity) risk and interest rate risk.

A firm's ability to utilise these hedging instruments will depend on their price (i.e. they may be prohibitively expensive for some firms), as well as accessibility and liquidity of derivative markets.

It is important to recognise that the use of hedging instruments does not eliminate risk completely:

- Many derivatives are bespoke in the sense that users have the flexibility to 'design' them according to the risks they anticipate that they face. It is possible for users to misjudge these risks and find, ex post, that the hedges put in place did not cover their exposures perfectly. Firms operating in competitive markets must absorb any losses arising from such misjudgements. It is appropriate for regulated businesses to be treated in the same way.

- All derivatives are designed to protect users against downside risk (e.g. the risk of a currency moving unfavourably against the party wishing to hedge). However, certain derivatives (e.g. futures and forwards) prevent users from making upside gains as well by locking in a price or other economic variable. When viewed after the fact, it may seem that the hedge was a poor decision because some upside gains were foregone. However, retrospective judgments of this kind should be avoided provided that the firm acted on the best information available at the time.

- As noted in Chapter 2, users of hedging instruments expose themselves to financial counterparty risk (i.e. the risk that the seller of the derivative will default on their obligations to the hedger). In general, these counterparty risks will be small if the agreements are with reputed, well-capitalised financial institutions, during stable economic times. However, financial market instability can increase counterparty risks, as demonstrated in recent banking crises.

Conventional insurance

Companies can purchase conventional insurance policies to protect themselves from certain types of risk. Conventional insurance transfers risk from the policyholder to the insurance company who is able to manage these risks by pooling them with the risks of other policyholders, and by holding appropriate capital reserves.

However, conventional insurance markets are not complete. There are certain risky events for which no conventional insurance exists. Section 3.2.6 discusses self-insurance as a method for managing such risks.

3.1.2 Contracting arrangements

Firms can also use contracts with third parties (e.g. suppliers and customers) to transfer some risk to those third parties.

- **Contracts with suppliers.** Firms can use contracts with suppliers to manage input cost risks (e.g. by agreeing the price of certain inputs to production for a period of time), cost volume risk (e.g. by capping the cost of certain services, such as construction work) and supplier risk (e.g. by specifying penalties for failure to deliver goods and services to certain timeframes/standards). Good supply contracting is an integral part of effective input procurement policies to manage cost-related risks.

- **Contracts with customers.** Firms can use contracts with customers to manage the impact of demand risk on revenues. For example, if demand is very volatile, firms with the flexibility to design their own tariff structures (i.e. unregulated firms, or firms operating under revenue caps) may use two-part tariffs with a high fixed charge component to dampen the effect of this volatility on revenues and, therefore, returns. In addition, firms might use long-term supply contracts to ensure greater certainty over future demand.

However, it is important to recognise that contractual arrangements cannot eliminate risk altogether because it is impossible to design complete contracts. Imperfect contracting arises because of unforseen contingencies, the costs of writing contracts, and the costs (including information costs) of monitoring and enforcing contracts (Tirole, 1999).[52]

3.1.3 Delay

Economic theory suggests that when an economic decision involves significant uncertainty about future revenues or costs, and when the costs associated with taking that decision are large and sunk, it can be optimal for firms to delay decision-making until the uncertainty is resolved (Dixit and Pindyck, 1994; Guthrie, 2009).[53] Flexibility over the timing of key decisions allows firms to mitigate downside risk by acting only when it is more certain that the likelihood of downside is low. This flexibility is particularly relevant to large investment decisions of the kind undertaken by network businesses. The value created by operational flexibility is equal to the expected value of losses avoided, and is known as the **option value** of waiting.

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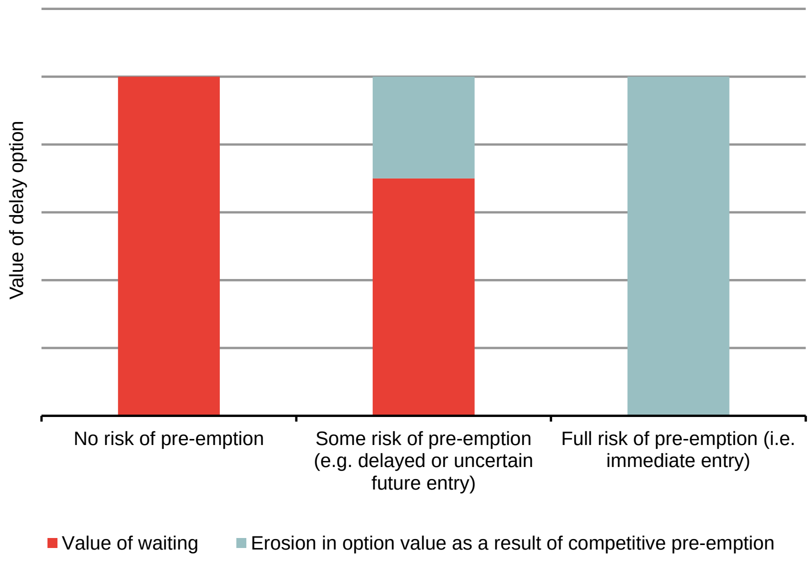
52 Tirole, J. (1999), 'Incomplete contracts: where do we stand?', *Econometrica* 67(4), 741-781.

53 Dixit, A. K., Pindyck, R. S. (1994), *Investment under uncertainty*, Princeton University Press; Guthrie, G. (2009), *Real options in theory and practice*, Oxford University Press: New York

However, economic theory also suggests that the threat of pre-emption by competitors erodes the option value of waiting. If there is a high risk that a rival may act profitably first, and the act of investing first might entrench the rival's dominance in the market, the option value of waiting might be very small. This is illustrated below in Figure 6.

Figure 6. The effect of competitive pre-emption on the value of waiting



Source: Frontier Economics

The Figure above presents three scenarios that may determine the value of waiting:

- When there is no risk of pre-emptive action by a rival, then the value of waiting is large.

- When there is some risk of pre-emption (i.e. that a rival will act first and enjoy a first-mover advantage thereafter), the value of waiting is eroded somewhat. Under this scenario, it would be optimal for the firm to bring forward the timing of the decision relative to the 'no pre-emption' scenario.

- When there is a very high risk of pre-emption (i.e. that rivals are ready to invest immediately to win a first-mover advantage), the value of waiting is eroded completely, and it may be optimal for the firm to act now rather than wait.

In addition to competition risks, the ability to delay action may be influenced by regulatory or government policy. For instance, the regulator or government may mandate that a firm should investment now rather than defer, in order to achieve certain policy objectives. This would remove managerial flexibility to delay action. Economic theory suggests that investing sooner than is optimal extinguishes a valuable delay option. Therefore, in order for the firm to be indifferent between investing now and investing later the firm would need to be compensated for the extinguishment of this option. In practice, it can be difficult to determine the value of waiting.

The size of the option value of waiting will depend on:

- The degree of uncertainty over the future;
- The size of the sunk costs associated with the investment (because this, coupled with the level of uncertainty determines the extent of potential stranding);
- The degree of flexibility that the firm has to delay the timing of investment; and
- The degree of competition between potential investors, and the size of the first-mover advantage that is at stake.

3.2 Regulatory options

This section explores some of the mechanisms that regulators may employ in order to share risks between customers and businesses.

3.2.1 Form of control

The two main forms of control used under incentive regulation are price caps and revenue caps, although regulators also employ variants of these.[54] Broadly speaking, the main difference between these two forms of control is that the regulator must forecast future demand in order to determine capped prices, but is not required to do so in order to cap revenues. To the extent that demand forecasts are susceptible to error, firms bear demand risk under price cap regulation, but do not under revenue cap regulation.

Therefore, a regulator that seeks to eliminate demand risk for the business may adopt revenue caps, which would lower the businesses' required rate of return. However, under a revenue cap system, firms ensure that they remain below the maximum allowed revenue determined by the regulator by adjusting their prices in line with demand. Hence, if demand is very volatile, revenue cap regulation can impose within-period price volatility on customers.

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54 Variants of these forms of regulation include: pure price caps; weighted average price caps; revenue yield caps; hybrid revenue caps; and pure revenue caps. See, for example, IPART (2001), *Form of economic regulation for NSW energy network charges – Discussion paper*, August.

In addition, Crew and Kleindorfer (1996) have argued that under certain conditions, revenue cap regulation can provide perverse incentives (and the freedom) for profit-maximising firms to set prices above the monopoly level.[55] Writing on the UK experience, Littlechild (2003) notes that although this is correct in principle, there is little to suggest that revenue cap regulation has led to pricing above the monopoly level:[56]

> Given the inelasticity of demand (at least in the short-run for the duration of the price cap, and with distribution and transmission costs of the order of 33% and 10% respectively of total electricity price), the transmission price increase necessary to reduce quantity demanded so as to achieve the constrained level of revenue at the lower level of output would be implausibly large. In any case, the revenue constraint in any year was formulated in terms of the previous year's quantities, so this alone would have precluded the utility from increasing price in the suggested manner.

3.2.2 Length of price control

An important choice that regulators must make when designing a regulatory framework is the length of time between regulatory resets. The length of the price control can influence firms' risk exposure in two ways:

- Under ex ante incentive regulation, if companies can beat the regulator's cost forecasts, these savings may be kept by the firms until the next regulatory review. The longer the interval between reviews, the stronger the incentive on firms to take steps to realise efficiencies (and to do so sooner rather than later). For this reason longer price control periods provide greater incentives for firms to manage input price risks, cost volume risks, supplier risks and financial risks. It follows that we might expect longer control periods to lower firms' risks.

- However, if firms fail to beat the regulator's cost forecasts (through their own inefficiency, factors beyond their control, or because regulatory targets are very onerous), the firms must wait until the next review in order for prices or revenues to be reset. The longer the regulatory period, the longer must firms wear the losses associated with under-performance. For this reason, we might expect longer control periods to increase firms' risks.

Which of these two effects dominates is an empirical question. The very limited empirical evidence that exists suggests that lengthening the regulatory period increases risk and, therefore, the cost of capital. Using a conceptual model, and simulated data, Gandolfi et al. (1996) show that under a price-cap system,

[55] Crew, M., A., Kleindorfer, P. R. (1996), 'Price Caps and Revenue Caps: Incentives and Disincentives for Efficiency', *Topics in Regulatory Economics and Policy Series* 24, 39-52.

[56] Littlechild, S. (2003), 'Reflections on incentive regulation', *Review of Network Economics* 2(4), 289-315

shortening the price control period reduces companies' betas.[57] The explanation they attribute to their result is that more frequent price resetting effectively 'buffers' the firms against cost shocks. As the control period is lengthened, the exposure to cost risk increases, thus driving betas up.

Using data on 100 regulated utilities in the US, Prager (1989) tests the effect of a range of different regulatory policies on the cost of debt of the regulated businesses.[58] He finds statistically significant evidence that "an incremental month of regulatory delay increases the cost of debt by 4.4 to 4.8 basis points".

As part of its new RIIO regulatory framework, Ofgem increased the standard length of its price controls from five years to eight years as it considered that this allowed businesses to engage in longer-term planning and action.[59] However, in doing so Ofgem recognised explicitly that lengthening the regulatory period could introduce more uncertainty for the businesses. Therefore, it concurrently introduced a range of uncertainty measures, including:[60]

- Indexation of the cost of debt via a 10-year trailing average process;
- A 'tax trigger', which provides automatic pass-through of additional tax costs arising from legislative changes;[61]
- A mid-period review of the outputs that the businesses are required to deliver over the control period;
- Reopeners on certain cost items; and
- A 'disapplication of price control' provision, which allows businesses a means to request Ofgem to reopen the entire price control within the period if the revenue allowance proves "insufficient to allow an efficiently managed company to finance its regulated activities".

57 Gandolfi, M., Jenkinson, T., Mayer, C. (1996), 'Price regulation and the cost of capital', *University of Oxford School of Management working paper*.

58 Prager, A., R., (1989), 'The effects of regulatory policies on the cost of debt for electric utilities: an empirical investigation', *Journal of Business* 62(1), 33-53.

59 In a consultation document, Ofgem explained its rationale for longer regulatory periods as follows: "current arrangements for setting five-year price controls encourage network companies to focus on cost minimisation over a five-year period only (if not shorter). This potentially limits the extent to which companies consider options for delivering outputs which reduce long-term costs (e.g. investment in research and development (R&D) and workforce skills, decisions on whether to repair or replace assets, taking a long-term view in determining the scale of network reinforcement)." See Ofgem, (2010), *Regulating energy networks for the future: RPI-X@20 Recommendations – Consultation*, July.

60 Ofgem (2011), *Decision on strategy for the next transmission price control – RIIO-T1*, March.

61 Ofgem made similar pass-through provisions for legislative uncertainty during DPCR5, for example in relation amendments to the Traffic Management Act 2004 and the Electricity Safety Quality and Continuity Regulations 2002.

3.2.3 Re-openers and automatic pass-through arrangements

One of the mechanisms that regulators may employ to reduce a wide range of risks (i.e. business and financial) over a regulatory period may be to specify 'reopeners'. These are provisions that allow businesses to apply to the regulator to revisit, *within* a control period:

- certain aspects of a regulatory decision (i.e. specific costs that are designated in advance as particularly uncertain) if outturns prove to be materially different from forecasts; or
- under extreme circumstances, the entire regulatory determination (e.g. if the decision causes an unanticipated financeability problem).

Reopeners can, in principle, reduce the cost of capital by dampening the effect of exogenous shocks (on costs and/or revenues) because the firm does not need to wait until the next regulatory period for allowances to be reset. This would have the effect of smoothing (actual and expected) returns over time.

The section above provided examples of two reopeners established by Ofgem recently as part of its RIIO framework. Ofwat also specifies a number of reopeners including:[62]

- An 'interim determination of K' (i.e. the expected efficiency factor) clause if, as a result of certain specified items, turnover is impaired by 10% or more;
- A 'substantial effect' clause, where Ofwat must consider an adjustment to price limits if turnover is, as a result of any factors, demonstrably impaired by 20% or more; and
- A general facility for firms to apply to Ofwat to re-examine the price control if the businesses are no longer able to finance their functions.

Prager (1989) showed, in his study of 100 US firms, that mid-period regulatory adjustments to a rate determination reduced firms' cost of debt by, on average, around 19bps. This is a small but nevertheless non-trivial figure, which suggests that re-openers can help reduce risk and the cost of capital.

Pass-through arrangements are provisions that allow automatic pass-through of certain notified costs, which were not included as part of ex ante allowances, but arise unexpectedly during the course of the regulatory period. In order to prevent large price increases during the period, these costs may be smoothed over several years, including over future regulatory periods if necessary. These

[62] In 2003 Ofwat agreed to adjust price limits for a firm because the demand it actually faced was materially lower than anticipated. In 2007 agreed to adjust price limits for two firms who, despite taking mitigating steps, realised significant bad debts. Ofwat (2011), *Cost of capital and risk mitigants – A discussion paper*, June.

notified items may relate to high-impact, low-frequency events outside the control of the business (e.g. storms, bush fires, and other natural disasters).

3.2.4 Ordinary pass-through provisions and strength of incentives

The building blocks framework used by regulators in Australia and elsewhere in the world 'build up' the revenues that regulated firms are allowed to earn using forward-looking estimates of costs and returns. Incentive regimes, such CPI – X, aim to provide only efficient allowances for costs and returns in order incentivise firms to achieve economic efficiency.

When designing the regulatory framework, regulators must choose the strength of the efficiency incentives built in. A system in which incentives are calibrated such that allowances are closer to actual, rather than efficient, outcomes (i.e. where there is a high degree of cost pass-through) is described as a **low-powered** regime. A system in which allowances are generally closer to the efficient benchmark (i.e. where there is very little cost pass-through) is described as a **high-powered** regime.

The incentive power of a regime can influence the risks that businesses are exposed to by affecting the volatility of returns. Firms' realised returns depend on the gap between actual costs and regulated revenues. Under a high-powered regime, this gap can widen or shrink over time in a volatile way, depending on the firms' ability to realise the efficiencies assumed by the regulator when allowances are set. However, if the regulator permits a high degree of cost pass-through by operating a low-powered regime, allowed revenues move more or less in line with actual costs, so returns are generally quite stable.

The system of network regulation that has prevailed in most of North America, known as **cost-of-service** or **rate-of-return** involves a high degree of cost pass-through so is clearly low-powered.[63] The systems of regulation that prevail in the UK, parts of Europe, Australia and New Zealand are incentive-based and are, by comparison to rate-of-return regulation, much more high-powered.

Camacho and Menezes (2013) show theoretically that incentive-based schemes, such as price cap regulation, should result in a higher cost of capital than low-powered rate-of-return regulation.[64] Alexander et al. (1996), and Alexander and

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63 Under pure rate-of-return regulation, regulated firms are guaranteed a certain rate of return on capital, and prices are set in order to achieve it. Under such a regime, any unforeseen costs faced by the firm could in principle be passed on to customers. If rates could be adjusted continuously to match changes in costs and demand, rate-of-return regulation would remove all of the firms' exposure to cost-related risk. In practice, however, regulatory reviews, although frequent, do not allow instantaneous pass-through of costs to consumers.

64 Camacho, F. T., Menezes, F. M. (2013), 'The impact of price regulation on the cost of capital', Annals *of Public and Cooperative Economics* 84(2), 139–158.

Irwin (1996), compare asset betas under different regulatory systems, varying from close-to-pure price-cap regulation to close-to-pure rate-of-return regulation.[65] They find that companies facing incentive-based regulatory systems tend to have higher asset betas than those that do not. Paleari and Redondi (2005) analyse the impact of regulatory events on British electricity companies' abnormal returns, beta and overall risk.[66] They find that betas increase as regulation becomes stricter.[67]

Not all incentive-based regimes are universally high-powered. Many incentive-based frameworks do permit cost pass-through on certain items. These items are those that are recognised as generally beyond the control of the firm (and therefore not amenable to optimisation in the way that controllable costs are). A good example of such a cost is corporation tax expense, which most regulators accept as largely beyond the influence of the firm.[68] On other cost items — particularly when firms have some, though not perfect, ability to mitigate risks — the controllability of costs is not clear cut. In such cases, the regulator has to make judgments about the reasonableness of steps that the firm might take, and the degree of pass-through to allow.

Another option that regulators might pursue is to prioritise the areas in which it wishes to drive efficiencies. To do this, the regulator could impose quite strict efficiency targets (supported by mechanisms to reward outperformance) in certain areas, whilst applying less stringent targets in others. This requires the regulator to take a holistic view of all the risks that businesses are exposed to, and the rewards on offer. Ofgem's RIIO regime is an example of a good recent

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65 Alexander, I., Mayer, C., Weeds, H. (1996), 'Regulatory structure and infrastructure firms: an international comparison', *World Bank Policy Research Working Paper* 1698; Alexander, I., Irwin, T. (1996), 'Price caps, rate-of-return regulation, and the cost of capital', *World Bank* note number 87.

66 Paleari, S., Redondi, R. (2005), 'Regulation effects on company beta components', *Bulletin of Economic Research* 57(4), 317–346.

67 A higher powered regime will allow less pass through of costs (and therefore allow less 'buffering' of cash flows) than a low powered regime. This will generally increase the volatility of the firm's cash flows (Alexander, et al. 1996). To the extent that the shocks that drive the variation in the cash flows of the regulated firms are economy-wide shocks, high-powered incentive regimes will lead to greater systematic risk exposure than low-powered incentive regimes. This idea is an extension of the work proposed by Peltzman (1976), Binder and Norton (1999) and others. Although it is not axiomatic that high-powered regimes result in greater systematic risk exposure than low-powered regimes, there are no good reasons to simply presume that *none* of the incremental volatility in cash flows is systematic. Peltzman, S. (1976), 'Toward a more general theory of regulation', *Journal of Law and Economics* 19, 211-240; Binder, J. J, Norton, S. W. (1999), 'Regulation, profit variability and beta', *Journal of Regulatory Economics* 15, 249-265.

68 Certain UK regulators do 'claw-back' the incremental interest tax shield benefits arising from businesses gearing up beyond the notional amount assumed by the regulator. However, these claw-back provisions are more about incentivising businesses to target an efficient level of gearing than optimising tax costs.

attempt at incentivising certain behaviours using rewards, but also balancing the risks that the businesses face in the process.

3.2.5 Preservation of RAB values

As noted in section 2.1.7, the materiality of stranding risk for a regulated network depends in large part on the regulator's chosen treatment of the RAB. A policy of not resetting RAB values periodically, even if the economic value of certain assets has fallen to zero prematurely, will insulate the firm from stranding risk. Conversely, the process of 'optimising' RAB values periodically leaving in, for instance, only assets considered 'used and useful', effectively strands those elements of the network that are removed from the RAB (Guthrie, 2006).[69]

Regulatory disallowances of sunk investments can have a significant impact on firms' risk and willingness to invest. During the 1970s, construction began in the US on many nuclear power plants. Most of these projects resulted in major cost and time overruns. In addition, the high expected oil prices and demand for nuclear power that motivated these projects was not realised. In response, regulators in some states allowed the firms they regulated to only partially recover their original investments, with disallowances totalling US$19 billion. Lyon and Mayo (2005) studied the effect of this policy on the investment behaviour of 132 US electric utilities between 1970 and 1991.[70] They found that companies scaled back construction of nuclear plants by $121 million per year if regulators imposed disallowances on other firms in the same state.

In order to avoid distorting investment incentives, regulators such as the AER have committed to not optimising RAB over time.

3.2.6 Self-insurance

Certain risks may only be partially insurable, very uneconomical to insure against, or uninsurable altogether in conventional insurance markets. These risks might relate to events with a very low-probability of occurring, but with the potential for a very large impact on the business.[71] Given the potential for large realisable losses, some form of protection against these risks would seem appropriate.

As discussed above, one way of dealing with such risks is through automatic pass-through provisions. Another, and potentially complementary, mechanism is

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69 Guthrie, G. (2006), 'Regulating infrastructure: the impact of risk and investment', *Journal of Economic Literature* 64, 925–972.

70 Lyon, T. P., Mayo. J. W. (2005), 'Regulatory opportunism and investment behavior: Evidence from the U.S. electric utility industry', *RAND Journal of Economics* 36(3), 628–44.

71 Examples of such events include catastrophic damage caused by natural disasters, terrorist attacks, other forms of third party damage, liability for environmental damage/losses, and fraud (see section 2.1.9).

self-insurance (Froot, 1999).[72] Under self-insurance, businesses are provided each regulatory period with an ex ante allowance (i.e. a 'self-insurance premium'), similar to an opex allowance, calculated as the expected value of the loss associated with the insured event.[73] These monies would normally be ring-fenced from the rest of the business (e.g. invested in a low-risk, liquid reserve fund), audited regularly and drawn down only if an event for which self-insurance provisions have been made arises, or if authorised by the regulator.

As discussed in Chapter 4, the AER has to date allowed self-insurance for certain items.

3.2.7 Indexation of costs

Indexation refers to the automatic adjustment of costs *within* a control period in line with some form of recognised index (e.g. an inflation index). Indexation should not be viewed as a pass-through of actual costs (and, therefore, a violation of incentives for efficiency gains). The index could be chosen to represent notional, or efficient, costs for the industry. The indexation process merely ensures that regulated prices or revenues reflect the evolution of these costs over the regulatory period. This eliminates much of the uncertainty faced by businesses in relation to those costs over the regulatory period. Indexation is closely analogous to the process of adjusting regulated prices or revenues by actual inflation within the control period, which largely removes inflation risk.

In principle indexation could be employed in relation to any cost faced by regulated business, provided that a robust and objectively-identifiable index exists to measure movements in these costs over time. Indexation makes most sense when applied to costs that are highly uncertain and difficult to hedge/manage.

Indexation of debt costs – a UK example

At its last price control for electricity distribution businesses, DPCR5, Ofgem introduced a 10-year trailing average mechanism to determine firms' allowed cost of debt. Under its new RIIO framework, Ofgem has committed to index the cost of debt over the control period using a trailing average process. The indexation mechanism is based on the following features:[74]

- A 10 year trailing average of a cost of debt index;

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72 Froot, K. A. (1999), *The financing of catastrophic risk*, NBER Project Report Series, University of Chicago Press: Chicago & London.

73 Here, the word 'expected' is used in the actuarial sense of probability of the event multiplied by the value of losses should the event occur.

74 Ofgem (2012), *Strategy consultation for the RIIO-ED1 electricity distribution price control*, September.

- The index chosen is the iBoxx non-financials 10+ maturity series, capturing the yields on sample of sterling-denominated corporate bonds a with broad A and broad BBB credit ratings; and
- Allowed revenues are updated annually to reflect changes in the index.

Ofgem identified the significant recent market volatility, future uncertainty over debt funding costs, and a desire to provide greater certainty to the businesses and customers as key motivations for its adoption of the trailing average approach:[75]

> Under the RIIO framework we said we would introduce an indexed allowance for the cost of debt, rather than the fixed allowance that was applied in the RPI-X regime. In the past, Ofgem tended to look at the 10-year trailing average on 10-year sterling (GBP) corporate bonds, as well as additional evidence, and then set a fixed allowance that was higher than observed rates in order to protect the network companies against the risk of the cost of debt rising during the price control period. The last 15 years or so have seen a sustained decline in the market cost of debt with the result that consumers have borne the brunt of a cost of debt allowance that was higher than the market rates.
>
> With current risk-free rate rates at historical lows and debt premia on BBB and A rated UK corporates back to their pre-crisis lows, it is unlikely that the cost of debt has much scope to decline further. However, it is unclear if and when the market cost of debt will increase, how fast it will climb and what levels it will reach during RIIO-T1 and GD1. With that in mind, we do not think that a fixed cost of debt allowance could be set with any confidence. We consider indexation to be the most robust option available to us to protect both consumers and the companies.

It is true that determining the cost of debt using a 10-year trailing average approach, rather than an 'on-the-day' approach, may violate the so-called 'NPV=0' principle.[76] It is also true that this approach may represent a departure from conventional finance theory that the cost of capital should, in principle, be based on the most current market data in order to capture forward-looking investor expectations. However, Ofgem took the view that it was more desirable to find pragmatic ways to reduce uncertainty faced by the businesses and customers, particularly during very turbulent market conditions, than to adhere to strict theoretical principles. The adoption of the trailing average approach was the result of this trade-off.

Cost of debt indexation in Australia

In October 2011, the Energy Users Rule Change Committee (EURCC) submitted to the AEMC a rule change request in relation to the NER. The

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75 Ofgem (2011), *Decision on strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1 Financial issues – Supplementary Annex (RIIO-T1 and GD1 Overview papers)*, March.

76 The preservation of the 'NPV=0' principle has been the subject of much debate in some Australian states and in New Zealand in the context of the choice of maturity assumption in the WACC, and in the choice of averaging periods applied to market data.

EURCC proposed the introduction of an Ofgem-style trailing average approach to determining, and indexing, the cost of debt applicable to electricity networks. The proposal was supported by several of the energy networks and some state treasury corporations, who argued that the approach would facilitate better management of financial risks. The AEMC neither prescribed nor dismissed the trailing average approach. Instead, it concluded that the AER was positioned best to decide on the most suitable method for determining the cost of debt allowance. The use of a trailing average approach remains a live issue in respect of the rate of return guidelines that the AER is developing at present.

The key reasons given by some energy networks and treasury corporations in support of the trailing average approach were summarised as follows by the AEMC:[77]

> A case was made, for example by the QTC, New South Wales Treasury Corporation (NSW T-Corp) and Ausgrid, that the current regulatory position of calculating interest rates on debt over a 20 to 40 day period encourages risk management behaviour in service providers that, in general, would not likely occur in the absence of such regulation. They argued that it also comparatively disadvantages large service providers whose ability to hedge large volumes of interest rate risk over such a short period is severely limited by the size and liquidity of the relevant markets.

As noted in section 2.2.3, the question over whether large businesses face real barriers to hedging their interest rate risks under the current regulatory approach is an empirical one, on which more evidence is needed.

On the question of whether a trailing average approach supports prudent debt management, the key strands of the argument advanced by certain proponents of the approach are the following:

- There are strong incentives on firms to match their actual debt funding costs to the costs allowed by the regulator. This point is also made by SFG (2012), who advised the AEMC on this issue, and we agree with it.[78]

- Prudent debt management by (in particular) large utilities involves a regular, staggered refinancing of existing debt. Refinancing all debt at once close to the regulatory reset would expose the firm to significant interest rate risk, and debt markets in Australia are not sufficiently deep for this approach to be feasible. We consider that this point is also correct, although we note that many large businesses source debt from overseas, where fixed income markets are deeper than those in Australia (see section 4.2.12).

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77 AEMC (2012), *Rule determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November, p.4.

78 SFG (2012), *Rule change proposals relating to the debt component of the regulated rate of return – Report for AEMC*, August.

- Under a cost of debt indexation approach, firms' actual debt costs should converge towards the cost of debt implied by the trailing average approach. This claim may not hold always for two reasons. Firstly, since the trailing average approach must necessarily be based on a benchmark cost of debt embodied in an index of some kind, there is no guarantee that firms will be able to achieve that benchmark rate each time they refinance. However, they may be able to get close using swap instruments.[79] Secondly, the businesses would always have to maintain a stable quantity of debt over time by ensuring that the quantity of debt refinanced each period equals roughly the quantity retired. However, one characteristic of network utilities is the need to occasionally make large, lumpy investments. Typically, much of these investments are financed using debt, so it is not realistic to assume that the businesses' debt levels will remain stable over time.[80]

Interestingly, whilst companies in Australia have generally favoured the idea of cost of debt indexation, it was opposed by a number of networks in the UK when Ofgem first introduced it. In contrast to the arguments advanced by proponents of the idea in Australia, objectors in the UK considered that indexation would make hedging *more*, not less, difficult:[81]

> The main argument against indexation is that no hedging mechanisms exist to protect the companies against movements in the index, which could push the companies to "track" the index by issuing 10-year bonds on an annual basis. Additionally, the companies have voiced a concern about the market cost of debt rising above the index, although it is not clear to us how this risk would be better addressed with a fixed allowance.

Ofgem (2011, p.21) rejected this view and stated:

> It has been argued in consultation responses that indexation would prevent the network companies from hedging against the risk of underperforming the cost of debt allowance. We asked Europe Economics to examine the extent to which networks companies currently hedge against our fixed allowance. This analysis is published today alongside this paper.
>
> Following discussions with banks, and a review of the information we received in annual regulatory reporting packs, Europe Economics concluded that the companies predominantly engage in pre-issuance hedging, in which they aim to secure the reference gilt yield that applies to their bond. Additionally, the companies may hedge

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79 There remains an open question about how easily, or cheaply, small firms can access the IRS market.

80 When the firms undertake lumpy borrowing over time, the overall cost of the businesses' debt portfolios will converge to the trailing average cost of debt only if modifications are made to the trailing average formula to reflect the changing mix of the firms' debt portfolios. This would be impractical to implement, particularly since the debt needs of different firms in the industry may vary.

81 Ofgem (2011), *Decision on strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1 Financial issues – Supplementary Annex (RIIO-T1 and GD1 Overview papers)*, March, pp.18-19.

> against inflation risk on non index-linked bonds by issuing inflation swaps. The typical time frame for such hedges is less than one year before the bond is issued, and usually less than three months.
>
> As Europe Economics concludes, cost of debt indexation in and of itself does not preclude the companies from entering into such hedges. Indeed, since indexation ensures that efficiently financed debt would be funded, even if the market cost of debt is above the cost of debt allowance at the time of issuance, it can be seen as a form of insurance for the companies.
>
> Furthermore, annual indexation of certain components of the cost of capital is a well-established practice among European regulators.
>
> Overall, we are not convinced by the arguments that indexation introduces greater risk for the network companies. Our decision is to set the cost of debt allowance based on an index that is updated annually.

One final point is worth making in relation to the trailing average approach. As noted above, regulated businesses have a strong incentive to match their funding costs to funding allowances made by the regulator. As SFG (2012) points out, a mismatch between the two would flow through to equity investors as more volatile returns. If proponents of the trailing average approach are correct that the mechanism would align better the businesses' actual funding costs with regulatory allowances, the volatility of equity returns should fall. This could in turn reduce the firms' cost of equity.

4 Assessment of risk exposure of regulated energy networks in Australia

This Chapter discusses the key characteristics of regulated energy networks in Australia that could affect their required WACC. It begins by outlining the general economic features of energy networks, focusing on how energy networks differ from non-energy and non-regulated businesses. It then goes on to describes the extent to which energy networks face the types of risks discussed in Chapter 2, relative to other business in general given the regulatory regime they face. Economic characteristics of energy networks

Like most other networks, the value that energy networks offer is derived from the number, size and type of their users. There is little benefit for an energy consumer to be connected to an energy network if no or insufficient energy suppliers are connected to that network. The reverse also holds – there is little benefit in an energy producer connecting to a network if the network connects few customers for the producer's output. The discussion in this section focuses on those characteristics of energy networks that set them apart from other networks and businesses more generally.

4.1.1 Natural monopoly

As noted in the previous section, regulated energy networks exhibit strong natural monopoly characteristics.

The most important natural monopoly feature of energy networks is substantial economies of scale. The per-unit costs of both electricity and gas network infrastructure tend to decline as the volume transported across a network increases. These declining average costs are experienced at both the transmission and distribution levels. For example, a high voltage electricity transmission line will transport the same power more cheaply (on a per unit basis) than two lower-voltage lines. Similarly, a large-diameter gas pipeline will transport a given quantity of gas more cheaply than multiple narrower pipelines. Further, because sources of energy supply tend to be geographically concentrated around certain locations (e.g. coal fields, gas reserves and mountains for hydro power), it is usually necessary to transport energy in bulk across long distances from sources of supply to major population or industrial centres. Equivalent or stronger economies apply at the distribution level – it would not conceivably be least cost to make multiple electricity or gas connections to a business or residential premises.

Another natural monopoly feature of energy networks is the difficulty and cost of obtaining easements and development rights for network paths. While undergrounding of network infrastructure can overcome these issues and has been implemented on occasion, it is generally far more expensive than above-ground development and is usually only undertaken where necessary to meet environmental requirements (e.g. Murraylink electricity transmission interconnector). Accordingly, it is generally far more feasible and practicable to use a single network path to transport energy than to use multiple parallel paths.

For all these reasons, it is usually inefficient to duplicate extensively electrical power lines or gas pipelines to serve market demand. Some degree of duplication does occur to provide back-up security,[82] or in rare cases where economies of scale are nearly exhausted.[83] However, due to their strong natural monopoly characteristics, facilities-based competition was never expected to emerge for energy networks in the same way as it was originally hoped-for in telecommunications services.

4.1.2 Limited competition

Energy-using appliances are often relatively expensive, long-lived and provide essential services to household, commercial and industrial customers. As such, energy networks are generally subject to fairly limited competition, at least in the short to medium term, relative to other types of businesses. However, electricity and gas networks do face some competition from one another, as well as from the emergence of distributed generation and energy efficiency measures.

Competition between energy networks

On the margin, electricity and gas networks compete against one another in the provision of energy to end-use customers.

In the late 1990s, the ACCC acknowledged the possibility that the expansion of the gas transmission network could lead to generators by-passing the transmission system by co-locating with load or large customers co-locating with generators. This could particularly occur at regional centres with high electricity transmission costs but located favourably with respect to gas.[84] As a result, the

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82 Due to the binary outage patterns of much electricity network infrastructure (i.e. in-service or out-of-service), electricity network planners often refrain from fully exploiting economies of scale in order to maintain discrete physical units of redundancy. For example, electricity transmission planners may prefer to build two lower voltage lines even though a single high-voltage line may be cheaper on average, in order to allow for the possibility of any given single line suffering an outage. Reliability standards based around such discrete redundancy criteria are known as 'deterministic reliability standards', or 'N-x" standards, where 'x' represents the number of credible contingencies that the network must be able to experience while remaining in continuous operation.

83 It was contended by a proponent (BG) of one of the multiple gas pipelines being developed from the Surat-Bowen Basin in Queensland to Gladstone that the granting of greenfield no-coverage exemptions in respect of those pipelines was appropriate because of the very limited cost savings that would arise from the development of a single very high-capacity pipeline. Further, a pipeline of such size had no precedent in Australia.

84 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999 (DRP), p.50.

ACCC allowed electricity transmission networks to offer 'prudent discounts' off their network charges to prevent inefficient by-pass.

Certainly, over the last decade, electricity generators have located in areas that would not have been possible prior to the expansion of the gas transmission system.[85] However, such generators still tend to rely on electricity transmission and distribution networks to take their power to end-use consumers. Clear-cut opportunities for efficient co-location (such as generators being located adjacent to aluminium smelters) have been exploited for some time and have been limited in number.

A more recent issue for established gas transmission pipelines is the development of new gas pipelines to LNG facilities that prepare CSM for export. Such new pipelines provide an alternative source of demand for existing and new gas supplies. By altering gas flows through eastern Australia, these new pipelines may result in reduced utilisation of some existing networks. However, as with the competition between electricity and gas networks, such new pipelines will only affect demand for most existing pipeline networks at the margin. The predicament of the most vulnerable gas networks is discussed further in Chapter 5.

Distributed generation, energy efficiency and smart grids

Greater competition for both electricity and gas networks is emerging from distributed generation sources such as solar photo-voltaic (PV) units. The installed capacity of PV increased from 23 MW in 2008 to 1,450 MW in February 2012.[86] AEMO forecasts installed capacity to reach 5,100 MW by 2020 and almost 12,000 MW by 2031. With the winding back of subsidised feed-in tariffs by state governments over the last two to three years, the rate of residential solar PV installations has slowed. However, it is expected to increase again from 2018.[87]

Over time, such developments and energy efficiency measures (such as LED lighting, improved insulation and more efficient heating and cooling systems) are likely to reduce the need to augment (and possibly extend) electricity networks. To the extent that gas networks serve gas-fired electricity generators, gas transmission networks could also suffer. The implications of growth in distributed generation and energy efficiency measures for different types of energy networks is also discussed in the next Chapter.

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85 Such an example is the Mortlake power station.

86 AEMO, *Rooftop PV Information Paper, National Electricity Forecasting 2012*, p.iii.

87 AEMO, *Rooftop PV Information Paper, National Electricity Forecasting 2012*, p.iii.

4.1.3 Long-lived assets

Both electricity and gas networks are largely comprised of assets with very long useful lives as compared to other types of businesses in the economy. For example:

- the AER's approved standard economic life for electricity transmission and distribution lines is approximately 50 years;[88] and
- the AER's approved standard economic life gas pipelines is 55 years and 30 years for compressors and other mechanical elements.[89]

This means that the cost of assets is recovered gradually over long periods of time. Other types of networks, particularly telecommunications networks where technological progress and obsolescence occurs more rapidly, may incorporate some assets with much shorter useful lives.

In addition, as discussed in section 2.1.10, the long-lived nature of the assets would mean that the businesses would have a preference for raising long-term finance over short-term finance.

4.1.4 Slow rates of technological change

Energy networks are characterised by slow rates of technological change relative to other types of businesses. This means that the risk of technological obsolescence is very small. Pipelines and electricity network elements installed decades ago are still in use. Incremental investments such as compressors (for gas pipelines) and voltage control equipment such as static var compensators (for transmission lines) can help increase the capability of existing infrastructure and prolong their effective lives.

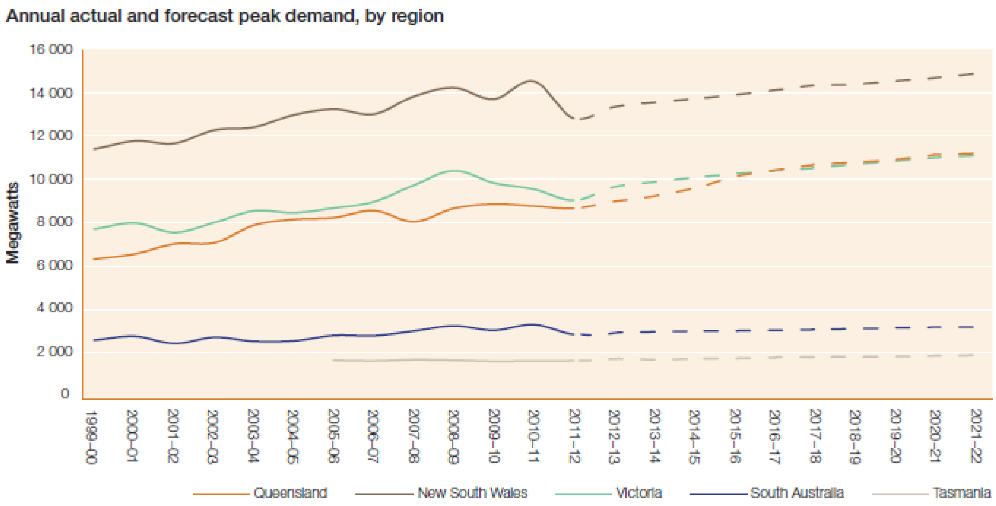
The principal innovation in electricity transmission has been the use of direct current (DC) technology for undergrounding (e.g. Murraylink) and undersea (e.g. Basslink) applications. Whilst the evolution of 'smart grids' has proceeded in Europe, the concept has been slower to affect Australian energy networks.

Technological change has mainly affected energy networks through the availability of cheaper reverse-cycle air conditioning systems over the last decade. This has lead to strong growth in peak summer demand, which has only recently been moderating (see Figure 7).

88 For example, for electricity transmission, see: Input tab in *Powerlink – RFM – amended – final decision.xlsm* spreadsheet, available at AER website: http://www.aer.gov.au/node/7945, accessed 24 May 2013; for electricity distribution, see: *PTRM Inputs tab in Powercor RFM Final Decision.xls* spreadsheet, available at AER website: http://www.aer.gov.au/node/7210, accessed 24 May 2013.

89 For example, see Input tab in *GasNet – PTRM – Final Decision.xls* spreadsheet, available at AER website: http://www.aer.gov.au/node/13556, accessed 24 May 2013.

Figure 7. NEM electricity demand



Source: AER, State of the Energy Market 2012, Figure 1.2a, p.29.

4.2 Exposure of energy networks to risks

Energy networks do face some business risks despite the absence of demand and supply-side threats and their slow rates of technological change. However, these risks tend to be smaller than the elemental risks that more technology-sensitive networks have faced in recent years and far less than most businesses in the economy. In addition, the regulatory framework helps ameliorate many of the risks by effectively transferring them to network users. This means that the exposure of energy networks to business risks is far less than non-network non-regulated businesses. Australian energy networks do face a moderate amount of refinancing and interest rate reset risks, given the recent increase in interest rate volatility and the use of a close-to 'on-the-day' approach to determining certain elements the cost of capital. This section discusses the nature and extent of various risks to which energy networks are exposed.

Our assessment of the materiality of risks faced by regulated energy networks in Australia, relative to other businesses in the economy, is summarised below in Table 5.

Table 5: Assessment of materiality of risks faced by regulated energy networks in Australia, relative to other businesses in the economy

Business risks	Networks' exposures	Financial risks	Networks' exposures
Demand risk – investment	Low	**Refinancing risk**	Medium
Demand risk – volume	Low to medium (depending on form of control)	**Interest rate reset risk**	Medium to high
Input price risk	Medium	**Illiquidity risk**	Low (large networks) Medium to high (small networks)
Cost volume risk	Low to medium	**Default risk**	Low
Supplier risk	Low	**Financial counterparty risk**	Low
Inflation risk	Low		
Competition risk	Low		
Stranding risk	Low		
Political / regulatory risk	Low to medium		
Other business risks	Low		

Source: Frontier Economics

4.2.1 Demand risks

As noted in Chapter 2, networks face two types of demand-side risks. The first risk derives from the need to forecast demand to determine how much should be invested in capital equipment or spent on maintenance and operations. The second risk derives from the need to forecast demand to determine how charges should be set to recover costs and earn reasonable return. For most businesses, these risks are closely linked – a business that underestimates demand will invest less *and* earn less revenue than it would have if it predicted demand accurately; a business that overestimates demand will invest more *and* earn more revenue than it would have if it predicted demand accurately. However, for regulated energy networks, these two types of demand risk can be treated separately and will be discussed in turn.

Investment/expenditure risk

A normal business needs to forecast demand to determine how much it should invest or spend to produce the level of output that it believes will maximise its profits. Due to high fixed costs, strong economies of scale and lumpiness, most energy networks need to make investment decisions well in advance of observing actual demand for their services.

However, the building block form of regulation applicable to regulated Australian energy networks largely insulates energy networks from much of the downside risk of over-investing due to over-estimating demand. Energy networks are penalised to some extent for spending more than forecast,[90] but they are not penalised deliberately for over-forecasting demand in the first instance.[91] Regulators in other jurisdictions, such as Ofgem in Britain, have used 'menu choice' regulation to elicit better forecasts from regulated businesses.

The result of under-investment in energy networks tends to be unmet or unserved energy, which is largely borne by network users. The result of over-investment tends to be higher network charges, which is also largely borne by network users because in Australia once investments are made they are included in the RAB until the investment costs are recovered fully.

For these reasons, energy networks generally avoid many of the risks of investing too little or too much to meet actual demand, as compared to other businesses more generally.

Demand/volume risk

Another reason energy networks need to forecast demand is to determine how charges should be set to recover costs and provide for a reasonable return on assets. For normal businesses, lower-than-expected volumes yield lower revenues while higher-than-expected volumes yield higher revenues.

The exposure of energy networks to demand or volume risk within a regulatory control period depends very much on the regulatory form of control applied by the AER. The two main forms of control applied in the Australian regulated energy sector are:

- **Revenue cap regulation**, which sets the maximum allowable revenue (MAR) for each year of the regulatory control period. The network business sets prices so as to not exceed the MAR. At the end of each year, prices for the following are adjusted higher (lower) to account for any under- (over-) recovery of revenues relative to the MAR. Under a revenue cap, an energy network faces virtually no revenue risk.

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90 Within a regulatory control period, by not being able to recover the actual return on and of the higher actual level of expenditure.

91 Those networks regulated under price caps are penalised indirectly through downside volume risk – see next sub-section.

- **Weighted Average Price Cap (WAPC) regulation**, which sets the amount by which the weighted average of prices for different services can change each year. The network business is free to adjust prices each year so long as the volume-weighted average change does not exceed the cap. Under a WAPC, an energy networks will face some revenue risk.

As energy networks' costs within a regulatory control period tend not to vary as greatly with the concurrent demand for their services as do their service costs, networks' profits may be more volatile under a WAPC than under a revenue cap. However, even under a WAPC, energy networks will face much lower profit variability due to changes in demand than other types of businesses more generally.

4.2.2 Input cost risk

Energy networks are potentially exposed to some input cost risks within a regulatory control period. Many energy network capital cost components are imported and made from commodities whose prices are set in international markets (e.g. copper, iron ore). These can be managed to some extent through financial hedges. To the extent that capital expenditure overruns occur, energy networks are usually able to add the overspend to their regulated asset bases at the end of the control period in which the overspend occurs, and these actual costs are then rolled forward into future periods. Operational inputs, such as the supply of skilled labour, may also vary unpredictably. Labour cost risks within a regulatory period can be mitigated through appropriate contracting practices. The periodic resetting of cost allowances, and provisions for the roll forward of the asset base based on actual capex, are features of the AER's current regime that go a long way towards mitigating input cost risk.

Where costs increase for reasons outside an energy network's reasonable control, the regulatory arrangements in the NER and the NGR incorporate pass-through and re-opener provisions. Pass-through provisions are designed to deal with specific changes in inputs costs within a regulatory control period that are outside the network's control, such as changes in taxes and regulations. Re-opener provisions are intended to be available in case of substantial and reasonably unforeseeable cost imposts.

To the extent that higher capital and operating costs persist beyond a regulatory control period, this can be taken into account in the forecasts for the subsequent period, thereby protecting the network from the cost increases to that date. Therefore, energy networks have far greater scope for managing these risks than businesses in the economy generally.

4.2.3 Cost volume risk

Due to the slow rates of technological change in energy networks and the broad familiarity that energy networks have with geographic conditions within their jurisdictions, energy networks face relatively modest cost volume risks, at least compared with other types of businesses. The quantity of inputs and the timing of project developments can usually be predicted with reasonable confidence. The key exception to this rule is costs or delays brought about by uncertain environmental approvals, which can be affected by political factors. For example, the Basslink project required an environmental assessment conducted by a Panel with members from three governments (Victorian, Tasmanian and Commonwealth), which took three years to complete.[92] However, even where delays occur, energy networks are able to recover a return on and off the delayed capital expenditure (relative to forecasts) under the incentive-based form of regulation that applies to them. Further, to the extent that capital expenditure overruns occur, the ability of energy networks to add the overspend to their regulated asset bases in most cases at the end of the control period mitigates their exposures to this risk.

4.2.4 Supplier risk

Supplier risks also tend to be reasonably manageable for energy networks relative to other types of businesses. The scale of most energy network investments is such that suppliers are usually large and financially stable. The global boom in energy network development over the last decade has meant that few suppliers of inputs to networks have become insolvent. To the extent that high demand for supplier services causes delays in network investment, the risks are generally borne by networks users rather than the networks themselves (as noted above). If anything, energy networks may increase their profits under incentive regulation if investment capital expenditures are delayed.[93]

4.2.5 Inflation risk

Revenue cap and price cap regimes traditionally employ a 'CPI – X' framework, where regulated revenues and prices are allowed to grow over time at the CPI-based rate of inflation, minus an annual efficiency factor (X). Under the AER's CPI – X framework, the annual inflation adjustment to revenues or prices is

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92 Basslink Joint Advisory Panel, *Final Panel Report*, June 2002, available at: http://www.planning.tas.gov.au/__data/assets/pdf_file/0004/156631/Basslink_proposed_interconnector_linking_the_Tasmanian_and_Victorian_electricity_grids_-_Final_Panel_Report.pdf, accessed 24 May 2013.

93 Given that networks can continue to earn a return on and of forecast expenditures for the remainder of the regulatory control period.

based on actual outturn inflation with a one-year lag.[94] The use of (lagged) outturn inflation eliminates largely (though not perfectly) the firms' exposure to CPI inflation risk.

4.2.6 Competition risk

The discussion above highlighted the limited competition (bypass) risks faced by Australian energy networks as compared to other types of (unregulated) businesses. Even where bypass can and does occur, energy networks often have the ability to recover foregone revenues from other (non-bypassing) customers through prudent discount regimes or accelerated depreciation arrangements approved by the regulator.

4.2.7 Stranding risk

As discussed in section 2.1.7, notwithstanding actual demand uncertainty or rates of technological obsolescence, the degree to which a regulated network is exposed to stranding risk depends on regulators' treatment of sunk investments. If these investments are safeguarded in the RAB, stranding risk will be generally quite low.

Regulatory stranding risks for energy networks in Australia are fairly contained. While the regulatory regimes incorporate some scope for *ex post* reviews of capital expenditures, broader optimisation risks have been almost entirely absent for nearly a decade.[95] In the case of electricity transmission, the ACCC originally considered that any stranding risks would be reflected in the return on capital.[96] However, it is not clear whether WACCs were adjusted downwards in the mid-2000s to account for the almost-entire removal of these risks.

4.2.8 Political/regulatory risk

As noted above, energy networks do remain exposed to some political and regulatory risks delays and costs as compared to other types of businesses, particularly relating to environmental impacts. As with under-investment risks more generally, part of the effect of delays is borne by network users who may experience diminished reliability. Networks may face cost blowouts as a result of delays, if delays mean that projects are developed less efficiently than expected. However, as noted above, networks can also benefit from capital expenditure delays through the form of incentive regulation to which they are subject.

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94 See, for example, ACCC (1999), *Statement of Principles for the Regulation of Transmission Revenues – Draft*, May.

95 At least since the ACCC's 2004 SRP (ACCC, *Statement of principles for the regulation of electricity transmission revenues – background paper*, 8 December 2004).

96 ACCC, DRP 1999, p.52.

Changes in government policy or regulation may increase costs more directly. For example, APA GasNet technical staff have expressed concern about increased pipeline safety standards applicable to urban and sensitive areas to control release rates being retrospectively applied to existing pipelines.[97] Some of these types of risks may be managed adequately through the pass-through and re-opener provisions in the NER and NGR.

An overarching political concern for regulatory networks relates to the 'essential' nature of their services and the fact that distribution networks in particular serve domestic and small business customers. This means that they are exposed to the risk of unpredictable government policy decisions designed to address consumer/voter concerns.

The development of clear guidelines by the AER on all aspects of its regulatory framework is potentially a very useful step towards enhancing regulatory certainty. Although these guidelines will be non-binding, the AER is required to explain any future departures it makes from the guidelines. This requirement should impose on the AER some discipline against arbitrary departures from its established framework.

An important institutional arrangement that can reduce regulatory risk is the structural separation between rule-making and rule-enforcement. In the Australian energy sector, the AEMC is responsible for developing, clarifying and updating the National Electricity Rules and National Gas Rules, which set out the key aspects of the regulatory framework. The AER is tasked with implementing these rules. Although the AER can and does have some input into the formulation of the rules, the AEMC is ultimately an independent body that is responsible for its own determinations. Furthermore, the AEMC's decision-making process is generally open and transparent. These governance arrangements, which are fairly unique in the world in terms of economic regulation, should in principle reduce the risk of discretionary decision-making.

Finally, the AER's determinations can be appealed to an independent decision-making body on their merits as well as on points of process and law. Whilst the mere existence of appeal rights is sometimes criticised as costly and open to abuse by the regulated businesses, there is no question that the threat of appeal results in more careful and reasoned decisions, and places limits on discretion that the regulator is willing to exercise. This is helpful in reducing regulatory risk. We note that not all regulated sectors in all Australian states have appeal rights and, in our experience, this is often a source of concern for the businesses affected. At the same time, we acknowledge that the scope for merits reviews for

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97 See *Statutory Declaration of Mark Fothergill*, 9th November 2012, para 19, p.4, available at AER website: http://www.aer.gov.au/node/13556, accessed 24 May 2013.

energy network regulatory decisions is presently undergoing changes. These changes will require:[98]

- The applicant (typically an energy network) to demonstrate that the original decision-maker (typically the AER) made an error of fact, exercised its discretion inappropriately or was unreasonable and that addressing the issue would lead to materially preferable outcomes in the long term interests of consumers; and
- The Australian Competition Tribunal to make much clearer links between its decisions and the long term interests of consumers, in accordance with the national electricity objective and the national gas objective.

When implemented, the changes proposed are likely to reduce the probability of energy networks to obtain favourable amendments to the AER's decisions.

4.2.9 Other business risks

There is a range of other risks that energy networks face, such as the risk of incurring liability (such as for bushfires), property risks, the risk of contaminated land, motor vehicle risk, fraud risk and so on. Many of these risks are not experienced to the same degree by other types of businesses.

The AER has historically allowed energy networks an allowance for self-insuring against these risks to the extent that they are (efficiently) not covered by insurance, not already remunerated through other elements of their regulatory building blocks and not recovered as pass-through items. Importantly, only insurable risks are allowed as self-insurance costs.[99] Further, when assessing whether particular risks or costs are to be treated as pass-through events or compensated through the self insurance component of the opex allowance, the regulator considers the foreseeability, probability, magnitude and controllability of those risks or costs.

4.2.10 Refinancing risk

As discussed in Chapter 2, refinancing risk derives from uncertainty over how interest rates will evolve in future. There is currently a significant amount of interest rate uncertainty. In this regard, we note that:

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98 Standing Council on Energy and Resources, *Regulation Impact Statement, Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks, Decision Paper*, 6 June 2013.

99 See, for example, AER, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Appendices*, June 2010, Appendix M, pp.245-250.

- **Australian interest rates have become more volatile** since the onset of the GFC. This is demonstrated in Table 6, which compares the volatility of CGS yields over two periods: the period since the failure of Lehman Brothers in September 2008 until late March 2013 (1,140 trading days); and a period of identical length before Lehman's collapse.[100]

Table 6: Daily volatility of CGS yields of different maturities before and after failure of Lehman Brothers

Period	Two years	Three years	Five years	Ten years
Before Lehman collapse (09/03/04 to 12/09/13)	0.58%	0.54%	0.45%	0.37%
After Lehman collapse (15/09/08 to 26/03/13)	0.91%	0.97%	1.00%	0.91%
Difference	+0.32%*	+0.43%*	+0.55%*	+0.54%*

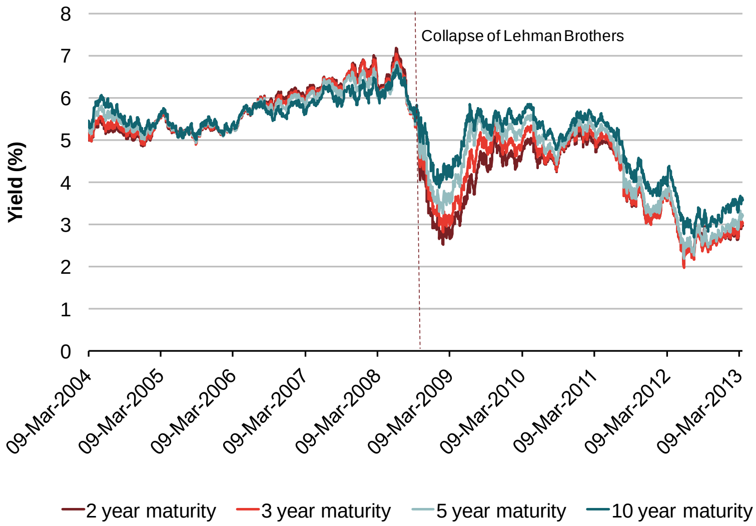
Source: RBA data, Frontier analysis

Notes: Statistically significant at the 1% level using a standard F-test and Levene's test for equality of variances

- **Australian government bond yields have fallen sharply** since the start of the GFC (Figure 8). No-one is certain whether this downward shift is a temporary phenomenon or a permanent structural change. However, the former seems more likely than the latter. A fairly persuasive explanation for the recent reduction in yields is that, in the face significant global financial market uncertainty, investors have sought out 'safe haven' investments such as debt issued by creditworthy sovereigns. This has pushed up the price of bonds issued by governments such as Australia's, and pushed the yields on these bonds down. If a rebalancing of risk explains much of the recent decline in Australian interest rates, it is plausible that as the global economy recovers investors will 'unwind' this rebalancing by shifting funds away from safe sovereign debt towards riskier assets. If as a result demand for Australian government debt falls, interest rates would be expected to rise once more. However, it is impossible to say with confidence when this will occur.

100 The failure of Lehman Brothers on 15 September 2008 was a key event in the start of the GFC.

Figure 8. Downward shift in CGS yields since onset of GFC



Source: RBA data, Frontier analysis

In our view, these two developments mean that the refinancing risk faced by Australian energy networks has increased as compared to what it was in the past.[101] However, it is essential to note that, by the same token, refinancing risk has also increased for all other businesses in Australia — regulated and unregulated. Therefore, although the absolute level of refinancing risk faced by regulated Australian energy networks has increased recently, the level of refinancing risk **relative to other firms** in the economy probably has not.

4.2.11 Interest rate reset risk

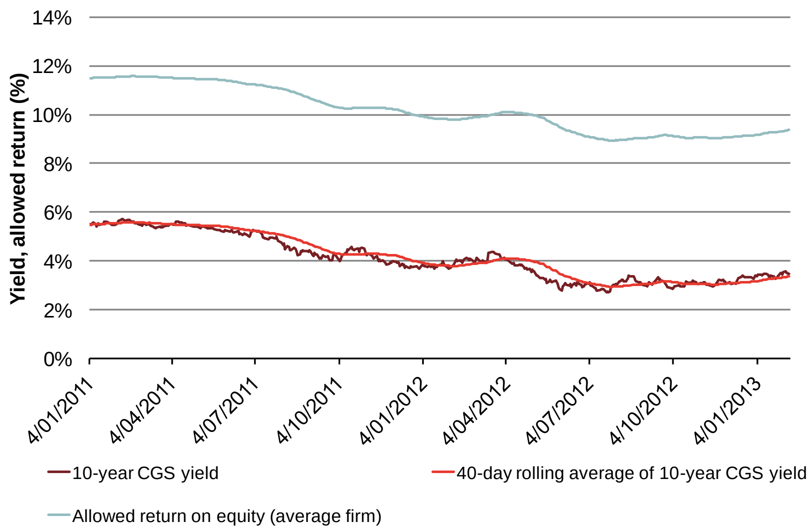
Interest rate reset risk refers to the possibility that the costs of finance adopted by the AER, when determining allowed rates of return periodically, do not match firms' actual cost of finance. Hence, whereas refinancing risk is not unique to regulated networks, interest rate reset risk is as it derives directly from the regulatory arrangements in place to determine allowed returns.

The AER seeks to determine a forward-looking rate of return. To this end, it has tended to apply a (close to) 'on-the-day' approach, where the risk-free rate is determined using a short-term (10 to 40 day) average of annualised CGS yields. The profile of returns that could be allowed by the AER will tend to be fairly variable over time by virtue of this short-term averaging approach. This, in turn, would tend to increase interest rate reset risk.

101 Note that the volatility of interest rate may have implications for the refinancing of equity as well as debt. However, the effect on the latter is generally more visible than the effect on the former as the cost of debt can generally be observed directly, whereas the cost of equity cannot.

This is illustrated by Figure 9 below, which plots over time the return on equity that the AER might allow a firm of average (i.e. beta = 1) risk. The calculations assume that the risk-free rate is determined by taking a 40-day average of the prevailing 10-year CGS yield, and a market risk premium (MRP) of 6% (a figure that the AER has tended to favour in recent years). As the chart shows, a determination for such a firm made in early April 2011 would have resulted in a return on equity allowance of about 11.5%. A determination made, using the same approach, for a firm of identical risk 12 months later would have resulted in a return on equity allowance of about 10.1% — a non-trivial difference of around 140bps — due to short-term market movements.

Figure 9. Profile of allowed return on equity for a firm of average risk (beta = 1)



Source: RBA data, Frontier analysis

Notes: Allowed return on equity assumes a MRP of 6% and an equity beta of 1

The cost of debt allowance provided for by the current regulatory arrangements can be shown to be variable over time for similar reasons. Some stakeholders have argued for a long-term trailing average approach to determining the cost of debt as a way of reducing interest rate reset risk, at least on the debt side. Clearly, such an approach would result in a very smooth profile for the allowed cost of debt. However, as noted in Chapter 3, the application of such a mechanism would not eliminate interest rate reset risk altogether. This is because the trailing average approach must necessarily be based on a benchmark cost of debt, and there is no guarantee that firms will be able to achieve that benchmark rate each time they refinance.

The degree to which firms can manage their own exposure to interest rate reset risk on the debt side depends on their access to hedging instruments, such as interest rate swaps. This remains an open empirical question for the AER to investigate.

4.2.12 Liquidity risk

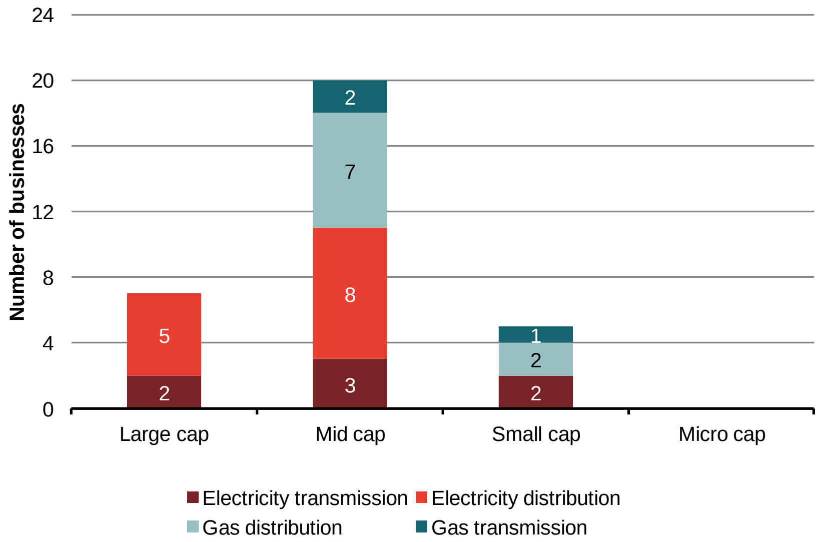
As discussed in earlier chapters, there is a tendency for the equity of small firms and privately-owned businesses to be less liquid than equity in large, quoted companies. To understand if equity investors in regulated energy networks in Australia are likely to be exposed to liquidity risk, we looked at how large these businesses are. A conventional way to classify businesses by size is to group them by market capitalisation into four broad categories: Large cap; Mid cap; Small cap; and Micro cap. There is no standard way in Australia to define each of these size groups. However, following the approach used in a relatively recent report by the ASX (2010) to categorise listed Australian companies into four size groups, we define the size bands above as follows:[102]

- **Large cap** – market capitalisation greater than $1 billion;
- **Mid cap** – market capitalisation between $100 million and $1 billion;
- **Small cap** – market capitalisation between $20 million and $100 million; and
- **Micro cap** – market capitalisation less than $20 million.

Since most regulated networks in Australia are not listed companies, market capitalisation data for these businesses are sparse. However, we can proxy for market capitalisation by estimating the equity value of RAB for each of these businesses. In order to do this, we multiply the current RAB value for each business by the proportion of notional equity typically assumed by the AER in its rate of return determinations, 40%. Using this approach, Figure 10 below plots the distribution of energy networks regulated fully by the AER by size.

102 ASX (2010), *Capital Raising in Australia: Experiences and Lessons from the Global Financial Crisis*, January.

Figure 10. Distribution of networks regulated fully by the AER by size



Source: RAB data obtained from AER, State of the Energy Market 2012*, pp.62-63, 106-108; AER (2011),* N.T. Gas Access arrangement proposal for the Amadeus Gas Pipeline 1 August 2011 – 30 June 2016*, July; AER (2013),* APA GasNet post-tax revenue model*; AER (2011),* Roma to Brisbane post-tax revenue model.

Notes: Equity value of RAB estimated as RAB x (1 – gearing), *where* gearing *is assumed to be 60%.*

This analysis is not meant to be an exact classification of network size, and we have necessarily had to make a number of assumptions about how different size groups are defined, and how the equity value of the regulated businesses is measured. However, from this indicative analysis, we can say that none of the networks regulated by the AER could be described as Micro cap entities, and very few as Small cap businesses. Most would probably be described best as Mid cap firms. These companies, and the truly large networks, are unlikely to have a size-driven liquidity problem. Illiquidity may be more of an issue for the five networks in the Small cap category.

Unlisted (privately-held) companies can also be more illiquid than listed companies. Presently, there are seven companies listed in Australia that own regulated energy networks.[103] Hence the majority of energy networks regulated in Australia are not traded publicly. One possible reason for why capital in privately held firms is more illiquid than capital in listed companies is because much of the commercial information about the former tends to be private. As discussed in Chapter 2, if potential external investors cannot evaluate the quality of the firm and its future prospects, due to strong asymmetries of information, it is more

103 These companies are: AGL Energy Ltd, APA Group, Duet Group, Envestra Ltd, Redbank Energy Ltd, SP Ausnet and Spark Infrastructure Group.

likely that investors will view such firms as riskier than firms for which information is available readily. Information asymmetries should generally be less severe with regulated firms than with unregulated firms since the regulatory process facilitates the disclosure of much information that would otherwise remain private (e.g. Asquith and Mullins, 1986).[104] Hence, in the case of regulated utilities, private ownership per se should not lead to strong inferences that the businesses face large liquidity risks.

As noted above, regulated networks traditionally utilise debt finance significantly. Businesses may face liquidity limitations to the extent that they raise capital in bond markets. Corporate bond markets are generally regarded as less liquid than equity markets. The lack of depth in the Australian corporate bond market has been has been identified as a particular policy concern for the government. The 2009 Johnson Review noted that:[105]

- banks play a significant role in providing debt finance to corporate in Australia; and
- firms seeking longer maturities or additional debt beyond bank finance, often have to resort to corporate bond markets in Europe and/or the US.

A 2011 government discussion paper on corporate bond market reforms raised these issues again.[106] Data compiled by the Reserve Bank (Figure 11) suggests that Australian corporate raise a significant quantity of bond finance overseas, and in some years offshore issuance has outstripped domestic issuance. AFMA (2012) has recently argued that:

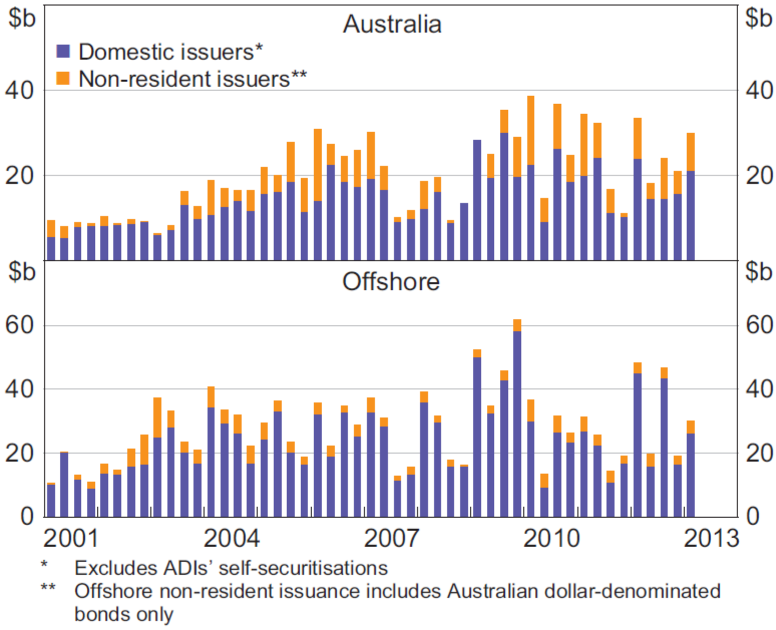
> The reason for this preference seems to be that it is easier to raise large amounts of capital at a competitive price in the deeper and more liquid capital markets offshore, particularly in the United States.

104 Asquith, P., Mullins, D. W. (1986), 'Equity issues and offering dilution', *Journal of Financial Economics* 15, 61-89.

105 AFCF (2009), *Australia as a Financial Centre: Building on our Strengths*, November.

106 Australian Government (2011), *Discussion paper: Development of the retail corporate bond market: streamlining disclosure and liability requirements*, November.

Figure 11. Gross issuance of non-government bonds in Australia and overseas



Source: RBA (2013), The Australian Economy and Financial Markets Chart Pack, May

Given the evidence, it seems likely to us that firms wishing to raise debt finance in Australia pay a premium to do so due to the apparent relative illiquidity of the domestic market. Larger networks, or networks funded by State treasury corporations, may be able to avoid these costs by raising finance in deeper markets overseas.

However, this may be infeasible for small, independent networks seeking to raise debt, since European and US corporate fixed income markets often have minimum issuance requirements that may be too high for the quantities of debt that small networks may wish to raise. This is consistent with the view expressed by the Australian Pipeline Industry Association in a recent submission to the AER:[107]

> It is generally accepted that the Sterling and Eurobond markets are likely to be difficult to access. In the Sterling market, lenders generally finance issuers with credit ratings of BBB+ or above. In the Eurobond market, the minimum issue size of €500 million is likely to be a barrier to an Australian service provider. Funding costs in this market are generally higher than in comparable markets, and the minimum issue size creates problems for Australian borrowers requiring cross currency swaps and future refinancing.

107 APIA (2013), *Response to Issues Paper – The Australian Energy Regulator's development of Rate of Return Guidelines*, February, p.28.

Therefore, in respect of debt finance, particularly for small networks, illiquidity may be a problem.

4.2.13 Default risk

Regulated energy networks generally face quite low exposure to default risk. Instances of default by networks regulated by the AER are very rare.[108] Indeed, there are very strong incentives for the businesses to ensure that they preserve high credit quality.

In recent years the AER has tended to assume that the businesses will maintain an investment grade credit rating when determining the cost of capital. Since the networks are not remunerated for bearing excessive default risk, there are quite strong incentives to remain investment grade.

Regulated energy networks in Australia have traditionally been considered by investors to have relatively stable returns. The relative safety of these companies as investments is a feature that large institutional investors value since this provides diversification opportunities for such investors. Maintaining this attractive feature creates further incentives for regulated energy networks to remain reasonably free of default risk.

As noted in Chapter 2, the amount of default risk borne by regulated businesses is contingent partly on regulatory outcomes. Recall that default risk refers to the risk that the cash flows generated by the firm will be insufficient to cover its financial obligations. To the extent that regulation plays a large part in determining the firm's cash flows, regulation affects the level of default risk faced by businesses. The fact that instances of default by regulated energy networks in Australia are rare, particularly in recent times, suggests that the current framework and approach to regulation applied by the AER is not inductive of significant default risk.

For the reasons above, we consider that regulated energy networks in Australia generally face quite low levels of default risk.

4.2.14 Financial counterparty risk

Financial counterparty risks are low generally, particularly when financial markets are not in crisis. We have seen no evidence that suggests these risks are especially material for regulated energy networks in Australia, relative to other businesses in the economy.

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108 One attendee of the AER workshop with stakeholders pointed out that the Dampier to Bunbury Natural Gas Pipeline went into receivership in 2004. This occurred when the owner of the pipeline at the time failed to meet its obligations in respect of a syndicated loan (see: ABC report, *Dampier to Bunbury pipeline goes into receivership*, 28 April 2004). However, this example of default is an exception for the industry.

4.3 Comparison to risks faced by water networks

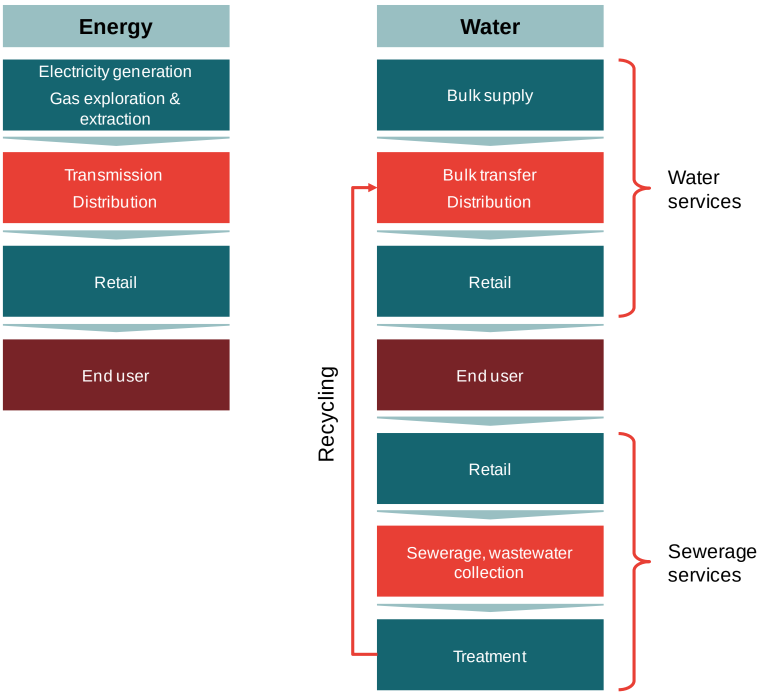
This section provides a comparison of the risks faced by regulated water networks and regulated energy networks in Australia. We begin by discussing the key characteristics of the water networks. We then discuss the key risks faced by water networks and contrast these to the risks faced by regulated energy networks. Finally, we draw some conclusions on the usefulness of regulated water companies as comparators to regulated energy networks in Australia.

4.3.1 Characteristics of water networks

Supply chain

As with the energy sector, the water sector network has several components. However, there are a number of fundamental differences between the way in which the water and energy sectors are organised, and regulated. Figure 12 provides a stylised illustration of the supply chains for the energy and water sectors.

Figure 12. Energy and water sector supply chains



Source: Frontier Economics

Note: The network elements in the two supply chains are shaded red

The first striking difference between the two sectors is that, unlike the energy sector, the water sector has two distinct elements to the supply chain — water services and sewerage services — with end users located between these two elements. There can be some interaction between the two parts of the water sector supply chain. For example, with the emergence of certain treatment technologies in recent years, recycled water has in some areas become a viable substitute for potable mains water, which can have implications for the utilisation of a water network (discussed in more detail later).

The second major difference in the organisation of the two sectors is the degree of integration within the supply chain. In the energy sector, electricity transmission and distribution (the network elements) have been separated structurally from generation and retailing. In contrast, in the network elements within the water sector (bulk transfer and distribution) have generally remained vertically integrated with all or significant parts of the rest of the supply chain. When thinking about the usefulness of regulated water companies as comparators to energy networks, it is the comparability of risks associated with the **network** elements of the supply chains that matters. However, given the strong degree of vertical integration typically applying within the water sector, the risks attached to water networks are not easily separable from the risks related to other parts of the supply chain.

It is also useful to draw a distinction between rural and urban water companies. In general:

- Rural water businesses are engaged primarily in the storage and delivery of bulk water, and the supply of irrigation schemes.

- Urban water businesses supply water to households and commercial customers; collect, treat and dispose of or recycle wastewater; and maintain the stormwater and sewerage networks.

In certain states (such as in Western Australia and South Australia) a single vertically-integrated water business supplies provide the vast majority of rural and urban services across the State. In other States, separate businesses supply different metropolitan areas typically with vertical separation of the bulk water and distribution/retail functions.

Natural monopoly

The bulk transfer and distribution elements of the water sector supply chain share the features of natural monopoly with regulated energy networks in Australia. These elements are generally large networks (in some cases spanning entire States) and therefore have significant scale economies. Many of these network assets are located underground, so construction of these water networks involves significant sunk costs. Like energy networks, it would generally be uneconomic/inefficient to replicate existing water networks.

Limited competition

Owing to their natural monopoly features, water networks in Australia have traditionally faced little supply-side competition. This is one of the key rationales for the application of economic regulation to water networks. However, recent developments in reverse osmosis technologies have led to the safe recycling of wastewater, which can then be distributed locally for non-potable uses. Arguably, this has made some parts of the bulk transfer and distribution elements of the supply chain more contestable. Water recycling is still emergent in Australia, but the use of recycled water is expected to grow over time.

The emergence of desalination technologies has also made bulk water services more contestable. However, as these technologies relate to a different part of the supply chain (bulk supply), they do not provide competition to water networks.

On the demand side there are few opportunities for substitution by customers. During times of plentiful rainfall, agricultural customers might use less irrigated water, and households/councils may use less mains water for the maintenance of gardens and parks. But, in general, end users are reliant on water companies to meet their essential water requirements.

Long lived assets

Like energy networks, the assets of regulated water networks tend to be very long-lived (i.e. lasting several decades). As with energy networks, this raises issues about the scope for asset stranding, and regulatory rules that affect the recoverability of sunk investments.

Slow rates of technological progress

In common with energy networks, water networks have been characterised by relatively slow rates of technological change and, therefore, little technical obsolescence. As noted above, the major innovations that have occurred in the sector recently are improvements in water treatment/recycling and desalination technologies.

Significant government involvement

A key difference between the energy and water sectors is the difference in roles played by the government. Although a number of energy networks are state-owned, government ownership is much more prevalent within the water sector. As noted above, in the energy sector, the rules that establish the regulatory framework are established by an independent rule-maker, the AEMC, and enforced by an independent, national regulator, the AER. In the water sector, regulation occurs, in almost all instances, at the state level.[109] As such, the regulatory frameworks governing regulated water companies are established through laws and regulations promulgated by state governments. In some instances, state water regulators play a much more minor role than the AER (e.g. simply monitoring prices, or investigating certain matters at the direction of the government), whereas the government assumes responsibility for determining prices. The multiple roles played by state governments in the water sector (i.e. as owners, rule-makers and, in some cases, as regulators) provides scope for conflicts of interest, the imposition of non-commercial objectives on businesses and political/regulatory risks that do not arise to the same extent in the energy sector

4.3.2 Risks that water networks may be exposed to

Volume risk

Volume risk for regulated water companies arises as a result of demand risk (i.e. uncertainty about future demand for water and sewerage services) and supply risk (i.e. uncertainty about the ability to supply water in order to meet demand).

Demand for water may be distinguished in terms of wholesale and retail demand. Wholesale urban water customers are typically urban water companies (who then distribute water to retail customers) and local councils. The main demand characteristics of these groups are the following:

- Retail customers comprise commercial / industrial users and households. A certain proportion of residential water use is for essential purposes (e.g. for hygiene and hydration). This type of water use is associated with a low income elasticity of demand. Likewise a base level of energy is required for appliances, illumination and cooking. This type of use is generally characterised as constant over a range of incomes. More discretionary uses, such as outdoor watering (or heating and air conditioning for energy), tend to be more sensitive to price.

- By comparison, commercial demand for water and power tends to be more elastic since production may be adjusted to account for changes in price or in the value arising from usage. Commercial customers can take a decision to scale back, or cease operations temporarily or permanently, depending on prevailing economic circumstances.

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109 There can be some exceptions. For instance, as of 2014 the ACCC will be responsible for regulating State Water under the Under the Water Charge (Infrastructure) Rules 2010. State Water was previously regulated by IPART.

- Wholesale demand for water is entirely a derived demand in the sense that it depends on demand from downstream retail customers.

Demand for wastewater services is proportional to consumption of water and rainfall (although this varies depending on the type of dwelling and in particular the extent of outdoor water use).

The greatest source of volume risk for regulated water companies is uncertainty over future water availability. Water shortages during periods of drought reduce the ability of water companies to serve customer demand, which has a direct impact on revenues if prices are fixed for the regulatory period, and shortages have traditionally been addressed by imposing water use restrictions to reduce demand rather than by increasing tariffs.

Water scarcity can also affect energy network revenues by reducing the water available for hydro and some thermal generation and, therefore, by reducing the utilisation of networks. However, electricity generation is not dependent entirely on water. A reduction in electricity supplied to the wholesale power market would drive prices up. These price signals would in turn encourage non-hydro generators (e.g. coal- or gas-fired plants) to scale production up, provided that these generators do not face binding capacity constraints. Meanwhile, there are several gas markets operating across Australia – the Victorian spot market (which operates in a broadly similar manner to the National Electricity Market, NEM) and the Short Term Trading Market (STTM), with hubs in Adelaide, Sydney and Brisbane. These markets help provide real-time signals for the wholesale demand and supply of gas. The effect of water scarcity cannot be mitigated to the same extent in the water sector for two reasons:

- In the urban water sector, there is no centralised marketplace equivalent to the wholesale power market that can provide clear price signals to suppliers to scale up supply in the event that certain producers are affected by water shortages.[110]

- Water companies are dependent on a single natural resource, water, in order to meet customer demand. In the energy market, if certain types of generators (e.g. hydro generators) are forced to scale back production, other forms of generation can generally be scaled up readily to meet unserved

110 However, in the rural water sector tradable water allocations do provide some price mechanism that can help during periods of scarcity. The value of such allocations should increase during water shortages. Those users who value water the least would, in principle, trade their allocations with those who value water the most. This should increase the likelihood that demand by those who value water the most will be met.

demand. Unmet demand cannot be served to the same extent in the water sector by switching between alternative forms of production.[111]

As with energy networks, the materiality of volume risks to water networks depends on the form of control in place. The form of control applied to water companies in Australia varies, even within states: some companies are price-capped, and some are revenue-capped. Those firms regulated under revenue caps can largely manage volume risk, whereas firms regulated under price caps will generally face greater volume risk exposure. This risk was illustrated starkly during the millennium drought.

Input cost risk

Water networks, like energy networks, face some input cost risks. The main inputs for water companies include: materials such as concrete and PVC pipes; treatment chemicals; power (e.g. to drive pumps and treatment plants); and labour (including skilled labour such as engineers). There can be future uncertainty about the cost of all these inputs. In addition, a number of the required inputs must be procured in global commodity markets and imported to Australia. This can also give rise to exchange rate risk. However, as with energy networks, these risks may be managed to some extent through hedging instruments and through the regulatory arrangements.

Cost volume risk

Water networks, like energy networks, typically involve large investments in physical capital. This could potentially give rise to construction risks. As noted above, the water sector is characterised by relatively slow rates of technological change. Therefore, complex technologies are not a significant driver of volume risk in the water sector. However, most water network assets are constructed underground. This can give rise to technical challenges and complexities in terms of maintenance of assets; it can be difficult to assess accurately where along an extensive network of pipes maintenance and repair is required. This can create uncertainty about the amount of work required to maintain a network in good order.

Although gas pipeline networks share these risks with water networks, electricity networks generally lie above ground and therefore do not create the same sorts of technical challenges.

111 The exception to this might be the situation where supply by desalination plants is scaled up to replace supply from dams during periods of water scarcity. However, seawater processed through desalination plants is generally much more expensive than water supplied from dams. This makes desalinated water an uneconomic alternative for rural use in particular.

Supplier risk

Regulated water companies do face supplier risk. However, in our view, there is no reason think that water networks face more or less supplier risk than energy networks

Inflation risk

Those water networks whose prices or revenue are capped are generally regulated using a CPI – X framework in which annual price adjustments take into account actual outturn inflation. As in the case of the networks regulated by the AER, this largely eliminates inflation risk. However, those networks whose prices/revenues are overseen less formally by State governments could potentially face price or revenue adjustments that are out of line with inflation, depending on the government's policy objectives. These businesses would face more material inflation risks.

Competition risk

As noted above, the key source of competition to water networks has the recent developments in the safe recycling of wastewater, which can then be distributed locally for non-potable uses. Recycled water usage is expected to continue to grow over time. Section 4.1.2 explained that regulated energy networks do face some competition threats (e.g. from distributed generation, solar PV, smart grids), but the effect of this competition has been fairly marginal to date. In both sectors there are emergent trends towards greater competition. We cannot say reliably whether the competition risks facing water networks outweigh those faced by energy networks, or vice versa. However, we can conclude that, in general, the risk of competition faced by these two industries is significantly lower than competition risks faced by unregulated businesses.

Stranding risk

Water networks, like energy networks, comprise long-lived assets. As noted above, all other things being equal, long-lived assets may be more exposed to the risk of future redundancy than short-lived assets. However, since energy and water networks both deliver essential services, the risk of stranding faced by these networks is generally quite low. Even if redundancy does occur, networks only become stranded if the regulatory framework disallows the recovery of sunk investment costs.

As noted above, *ex post* optimisation of the energy networks by the AER has largely been absent for nearly a decade. Given the scope for variation in the regulatory approaches taken by state level water regulators, and the role played by state governments within the regulatory process, it is difficult to draw similar conclusions for water networks. Whereas some regulators such as Victoria's

ESC has not pursued *ex post* reviews, ESCOSA has expressed a willingness to consider *ex post* reviews:[112]

> On the issue of carrying out an ex-post review of capital expenditure, whilst the Commission notes the level of governance that currently exists (as described above), it is not convinced that this governance will necessarily drive only prudent and efficient expenditure.
>
> Ex-post reviews of capital expenditure are commonplace in other Australian jurisdictions and in the UK, providing an additional level of comfort to consumers that they are funding only prudent and efficient investments. SA Water states that it has well established procedures, through its existing project development and approval processes, and that these ensure that its forecasts are prudent and efficient. Assuming that this is the case, an ex-post review of capital expenditure should add no regulatory risk for SA Water.

In addition, the greater scope for political oversight within the water sector could permit less formal regulatory decision-making than that undertaken by the AER, which could include the disallowance of certain sunk investments. We are unaware of any situations in which this has occurred within the water sector, but it remains a possibility.

Therefore, there would appear to be somewhat greater scope for asset stranding for regulated water networks than for regulated energy networks (although there is likely to be some variation between States). It is very difficult to say how much more material this risk is for water networks as compared to energy networks.

Political/regulatory risk

A key difference between regulated water and energy networks is the level of government involvement in terms of ownership, rule-making and regulatory oversight. Although some energy networks are still government-owned, most are in private ownership. In contrast, most water companies in Australia are owned by State or local governments.

In addition, all regulated energy networks in Australia are overseen by an independent, national economic regulator, the AER. State governments, who may be owners of the networks no longer play a major, direct role in the regulation of these companies. In the water sector there is the range of government involvement:

- In certain states, such as Victoria, the ESC has full responsibility for regulating prices/allowed revenues and quality of service.
- In some states, such as Western Australian and South Australia, the economic regulators (the ERA of Western Australia and ESCOSA of South

112 ESCOSA (2012), *Economic regulation of SA Water's revenues: Statement of approach*, July.

Australia, respectively) undertake detailed analyses and produce regulatory determinations on pricing/allowed revenues. However, these determinations are recommendations to the State government. The State government has ultimate authority to approve or reject those recommendations.

- In some States, such as Queensland and the Northern Territory, the economic regulator may be directed by the government to monitor the pricing practices of certain designated companies, arbitrate disputes between the companies and third parties, and at the direction of the government, investigate competition matters. Any economic intervention (e.g. in terms of prices) is the responsibility of the government.

In most States, the economic regulatory framework governing water companies is established through state laws and codified regulations that are promulgated usually by the governments themselves. In the energy sector, the rules governing the regulation of networks are promulgated by the AEMC, which is an independent rule-making body.

In the water sector, the multiple roles played by the government, as owner, rule-maker and key decision-maker in the regulatory process could give rise to conflicts of interest and opaque decision-making. This represents a potential source of political/regulatory risk that is largely absent in the energy sector.

In addition, there is no formal mechanism for regulated water companies to appeal regulatory determinations. In contrast, as noted above, regulated energy networks have the facility to appeal the AER's regulatory determinations on points of merit, process and law to a higher body, the Australian Competition Tribunal.

For these various reasons, it is reasonable to conclude that regulated water companies are exposed to greater political/regulatory risks than regulated energy networks.

Other business risks

Water networks face risks from natural disasters or other catastrophic events such as earthquakes, bushfires, terrorism attacks, floods which may result in destruction or damage to infrastructure assets or undermine the ability of networks to provide services or protect public health and safety. There may also be risk attributable to more gradual changes such as the potential effects of climate change on sea level rise and higher temperatures. Many of these risks are common to energy networks.

Refinancing risk

Water and energy networks face very similar exposure to refinancing risks. The volatility of interest rates affects all firms in the economy, but particularly those businesses that are intensive users of debt finance. As regulated network utilities, water and energy networks have historically been significant users of debt finance.

Interest rate reset risk

As noted above, interest rate reset risk is unique to regulated businesses because it arises as a result of the regulator resetting allowed returns periodically; unregulated companies do not face this risk. Interest rate reset risk faced by regulated networks is exacerbated by a close-to-on-the-day approach to resetting rates. As Table 7 shows, this approach is currently used by the AER and most of the independent State level water regulators (although we note that the AER is currently reviewing this approach). So, in this regard, regulated energy and water companies face a similar degree of interest rate reset risk.

Table 7: Risk-free rate and cost of debt maturity assumptions made by AER and State level water regulators

Regulator	Averaging period	Maturity assumption
ERA	20 days	5 years
ESC	40 days	10 years
ESCOSA	20 days	10 years
IPART	20 days	5 years
QCA	20 days	5 years
AER	10 to 40 days	10 years

Adapted from: IPART (2012), Review of method for determining the WACC: Dealing with uncertainty and changing market conditions, December, Table 3.1

A mismatch between the rates allowed by the regulator and businesses' actual financing rates could also occur if the regulator's maturity assumption deviates significantly from the term over which businesses finance themselves. Like regulated energy networks, water networks typically seek to finance themselves over long horizons. The AER, ESC and ESCOSA assuming reasonably long funding periods, which are likely to match more closely the funding term of the businesses they regulate. However, other State regulators assume a much shorter funding term. The businesses overseen by those regulators might be expected to face greater interest rate reset risk.

Liquidity risks

As noted above, small businesses tend to be more illiquid than large businesses. Therefore, when considering if water networks may potentially face large illiquidity risks, it is helpful to consider the size distribution of these networks. However, given the vertically integrated nature of most regulated water companies, it is challenging to identify the size of the *network* element of those companies. This makes like-for-like comparisons between regulated water and energy networks difficult.

Notwithstanding this caveat, RAB data on regulated water networks are available in regulatory determinations. Given the large number of water businesses in Australia, we have not undertaken an exhaustive survey of the size distribution of these firms. However, a sampling of recent determinations on RAB values for regulated water businesses (Table 8) suggests that, with the exception of a few networks, regulated water businesses are generally fairly large. This is indicative that water networks may not face larger liquidity risks than energy networks.[113]

Default risk

As with regulated energy networks, water networks tend to be fairly safe, stable businesses. Instances of default are extremely rare, and regulated water networks typically maintain investment grade ratings.

Financial counterparty risk

In our view, there is no reason to believe that water networks face any more or less financial counterparty risk than regulated energy networks.

113 Another way to assess the relative liquidity of energy and water networks would be to compare the liquidity of traded assets issued by these networks. A fairly standard way to compare the liquidity of traded assets is to examine the bid-ask spreads of such assets. This approach may be applied to bonds issued by energy and water networks. However, the bid-ask spread approach cannot be used to compare the relative liquidity of equity issued by energy and water networks since no water networks in Australia are listed.

Table 8: Recent water business RAB determinations

Water business	Date of determination	RAB value	Notional equity value (60% gearing)
Sydney Water[1]	June 2012	$13.4 billion	$5.36 billion
Water Corporation[2]	January 2013	$9.6 billion	$3.84 billion
Melbourne Water[3]	June 2013	$8.8 billion	$3.52 billion
SA Water (retail water)[4]	May 2013	$7.7 billion	$3.08 billion
Hunter Water[5]	June 2013	$2.2 billion	$880 million
Sydney Desalination Plant[6]	December 2011	$1.3 billion (for 2012/13)	$520 million
State Water[7]	June 2010	$715 million (for 2012/13)	$286 million
Sydney Desalination Plant (distribution pipeline)[6]	December 2011	$655.1 million (for 2012/13)	$262 million
Gosford Council[8]	May 2013	$593.3 million	$237 million
Wyong Council[8]	May 2013	$431.8 million	$173 million
Goulbourn-Murray Water	June 2013	$190 million	$76 million
Lower Murray Water (rural)	June 2013	$61.8 million	$24.7 million
Southern Rural Water	June 2013	$35.8 million	$14.32

Sources: [1] IPART (2012), Review of prices for Sydney Water Corporation's water, sewerage, stormwater drainage and other services From 1 July 2012 to 30 June 2016 – Final report, June; [2] ERA (2013), Inquiry into the Efficient Costs and Tariffs of the Water Corporation, Aquest and the Busselton Water Board, January; [3] ESC (2013), Price Review 2013: Greater metropolitan water businesses – Final decision, June; [4] ESCOSA (2013), SA Water's water and sewerage revenues 2013/14 – 2015/15 – Final Determination, Statement of Reasons, May; [5] IPART (2013), Hunter Water Corporation's water, sewerage, stormwater drainage and other services – Review of prices from 1 July 2013 to 30 June 2017 – Final report, June; [6] IPART (2011), Review of water prices for Sydney Desalination Plant Pty Limited From 1 July 2012 – Final report, December; [7] IPART (2010), Review of bulk water charges for State Water Corporation – From 1 July 2010 to 30 June 2014 – Final report, June; [8] Gosford City Council and Wyong Shire Council Prices for water, sewerage and stormwater drainage services from 1 July 2013 to 30 June 2017 – Final report; [9] ESC (2013), Price review 2013: Rural water businesses – Final decision, June

4.3.3 Conclusion on comparability of risks of water and energy networks and implications for benchmarking

There are many similarities between the characteristics of regulated water and energy networks. They both have strong natural monopoly features and are characterised by slow technical progress and long-lived assets. In addition, many of the risks faced by the two types of networks are also similar.

However, there are two principal differences between the two sectors:

- Regulated water networks are exposed to greater supply-driven volume risk, arising from uncertainty around future water availability, than are regulated energy networks. Supply of energy is not as dependent on a single natural resource as supply of water and sewerage services. Furthermore, the NEM, the Victorian gas spot market and the STTM provide clear price signals about supply shortages, which participants can respond to by adjusting output or consumption. There is no analogous price signalling mechanism in the water sector that acts on suppliers.

- Government plays multiple roles in the water sector (as owner, rule-maker and, in many cases, regulatory decision-maker). This increases the scope for conflicts of interest and political/regulatory risk. By contrast, government plays a much smaller role in the energy sector; its participation is largely confined to ownership of certain networks, and as maker of broad policies and laws.

Notwithstanding these differences, regulated water networks in Australia are probably the closest comparators available to regulated Australian energy networks. Given the similarity of their activities and characteristics, water networks and energy networks are, in principle, reasonable comparators to one another (see also Frontier, 2010).[114, 115]

Having established that, the question is whether the AER should, *in practice*, use evidence from water networks when estimating the cost of capital for regulated energy networks? The answer depends on whether the AER is estimating the risk component of the cost of equity or the cost of debt.

Evidence on the cost of equity

There are three possible sources of evidence on the covariance risk component of the cost of equity for water companies:

- Market evidence on regulated Australian water networks;
- Regulatory precedent from various Australian regulators; and
- Market evidence on regulated overseas water networks.

At present, there are no listed water companies in Australia. Without share price data on these companies, it is not possible to calculate sufficiently reliable historic returns for these firms to implement the asset pricing models (surveyed in

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114 Frontier Economics (2010), *The cross sectoral application of equity betas: energy to water*, April.

115 Indeed, Ofgem in the UK has traditionally estimated CAPM betas for the energy networks it regulates using, inter alia, estimates of betas for regulated UK water networks.

McKenzie and Partington, 2013) used conventionally to estimate the covariance risk of these firms. That effectively rules out the first possible source of evidence.

Precisely because of this data limitation, State regulators of water businesses in Australia have tended to evidence the AER's assessment of the covariance risk of regulated Australian energy networks to inform their estimates of covariance risk for the water companies they regulate. If the AER were to then employ precedents from these state regulators, it would introduce circularity to the analysis by effectively referencing its own past decisions. We think that this would be misleading and unhelpful. Therefore, we recommend that the AER not rely on precedent from Australian regulators of water businesses to inform its estimate of covariance risk for energy networks.

Therefore, the only source of evidence remaining to the AER is market evidence on regulated water networks overseas. Listed, regulated water networks do exist in the UK and the US, and market data on these companies could be collected. However, it is important that this evidence be treated with some caution because:

- the structure of the water companies overseas may differ from water and energy networks in Australia;
- the regulatory arrangements governing water networks overseas may differ from water and energy networks in Australia; and
- water networks overseas may be exposed to different macroeconomic factors and risk drivers than water and energy networks in Australia.

Notwithstanding these caveats, we think it is worthwhile to at least explore the overseas evidence available.

Evidence on the cost of debt

- As noted above, regulated water and energy networks face fairly similar financial risks. Hence, the AER could examine traded debt issued by regulated water networks in Australia to adduce evidence on the debt premiums that could apply to regulated energy networks in Australia. In Chapter 6 we provide a set of criteria that the AER could use to identify suitable debt comparators. However, if the AER chooses to take a comparator approach to estimating the cost of debt, it may be preferable to use as primary evidence debt issued by energy networks, and evidence on debt issued by water networks as supplementary evidence. This is because, the two types of networks share similar, but not identical, financial risks.

5 Risk exposures of different energy networks

A key aspect of this assignment is comparing and contrasting the risk exposures of different types of energy networks: electricity transmission, electricity distribution, gas transmission and gas distribution. In a similar manner to the previous Chapter, this Chapter begins by outlining the major differences in the economic characteristics of different types of energy networks and then proceeds to discuss the extent to which the different types of networks face similar or different levels of exposure in respect of certain key risks.

5.1 Economic characteristics of different energy networks

As discussed in Chapter 4, energy networks in general exhibit a number of characteristics that motivate policy-makers to apply regulation. These characteristics include economies of scale (often leading to natural monopoly), limited competition, long-lived assets and slow rates of technological change.

While all energy networks have these features to some degree, there are some important differences between different types of energy networks that should be noted.

Essential service

Electricity is regarded as an 'essential service' to a greater extent than gas. This means that while many consumers could – over time and subject to the replacement of existing heating and cooking appliances – adjust to the absence of gas supplies, they could not adjust to the absence of electricity. Partly as a consequence, most (but not all) electricity transmission and distribution networks are subject to stipulated reliability standards. These standards often oblige network owners to invest in a manner that builds-in a certain amount of physical or technical redundancy in the operation of their networks to allow for the failure of particular network elements. Gas networks are not subject to the same requirements.

Technical interdependence

Another difference between network types is that electricity networks exhibit greater technical interdependence than gas networks. This is due to the physics of power flows in the alternating current (AC) networks that are most prevalent across Australia. A fault in one part of an AC network or an outage of a generator connected to a certain part of the network can affect power flows in another part of the network much more immediately and severely than a fault in a gas network. Accordingly, the result of a fault in an electricity network or a connected generators can be cascading failures and total system blackout events, such as occurred in the northeast United States in 2003 and in northern India in 2012. Such failures can cause irreparable damage to network elements and connected generators as well as connected customers' plant and equipment. When gas network elements fail, network operators generally have time to take action to prevent total system failure and irreparable damage. Greater technical interdependence is another important reason why electricity networks are subject to detailed planning and operating standards.

Competition

Another characteristic that varies between networks to some extent is the degree of competition faced by different types of networks. As noted in Chapter 4, electricity and gas networks do compete with one another at the margin. To date, this has not resulted in major changes in the utilisation levels of existing gas or electricity network assets. However, two developments could change this in the future.

First, if eastern Australian gas prices rise due to the development of LNG facilities at Gladstone, it is possible that certain existing gas pipelines or networks could experience reduced demand over time as customers switch to using alternative pipelines or to substituting towards the use of more electricity. Such a switch could be aided by the second development – the increasing efficiency of domestic electric reverse-cycle air-conditioning and heating units. Combined with lower (or non-existent) carbon prices, this may make gas a less attractive fuel for space heating than it has been in recent years.[116] These risks are discussed further in the next sub-section.

Both electricity and gas distribution networks have also been relatively insulated from other forms of competition. The expansion of solar PV and other forms of micro-generation noted above have and may continue to reduce demand, but it is unlikely to allow complete by-pass of at least electricity distribution networks in the foreseeable future (see the discussion on demand risks below).

Asset life and technical change

All energy networks share the characteristics of long-lived assets and slow rates of technological change. However, electricity networks are probably more vulnerable to technological change within upstream and downstream activities than gas networks. In particular, intermittent generation such as solar PV and wind plant can increase stresses on electricity networks. For example, on the upstream supply side, increasing volumes of wind generation may affect system

116 Reverse cycle heating pumps produce heat approximately three times more efficiently than traditional electrical heaters, making them approach natural gas heating costs in some States.

stability and frequency response characteristics.[117] Grid-connected renewable energy sources also tend to be offered into the market at low prices, which can increase network constraints. On the downstream consumer side, existing electricity distribution networks were not developed to accommodate substantial injections of solar PV generation into the network. This can create voltage stability issues that require additional investment.

5.2 Key differing risk exposures

This section discusses the key areas where risk exposures differ across different types of energy networks, taking account of the nature of each type of risk as well as the extent to which the applicable regulatory framework helps to ameliorate the risk.

5.2.1 Demand/volume risks

Variations in the demand for energy network services may subject networks to demand-side or volume risks both through the effect on required levels of expenditure and through the effect on revenues.

In general, we accept the proposition put forward by the APIA that gas networks (particularly transmission pipelines) tend to experience – and are likely to experience in future – greater demand variability and vulnerability than electricity networks.[118] We note in particular the following factors:

- Electricity is more of a 'fuel of necessity' than gas, with electricity typically able to substitute for gas whereas the reverse is not usually the case.

- Gas transmission pipelines tend to serve a smaller number of customers and/or final consumers than electricity transmission networks.

Another factor we consider important is that gas transmission pipeline owners may own one pipeline or a small number of discrete pipelines often across multiple jurisdictions. By contrast, electricity transmission networks typically own and operate the bulk of the transmission network in their respective states. This makes gas transmission pipelines generally subject to greater supply-side competition from other pipelines or shifts in demand than electricity transmission networks.

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[117] Energynautics, *Lessons Learned From International Wind Integration Studies, AEMO Wind Integration WP4(A), Commissioned by the Australian Energy Market Operator*, 16 November 2011, p.4.

[118] Australian Pipeline Industry Association, *Response to Issues Paper, the Australian Energy Regulator's development of Rate of Return Guidelines*, 20/2/2013., Schedule 3

As noted above, the development of the Queensland LNG export industry may increase competition and risks for existing gas transmission and potentially distribution pipelines. These risks arise for two reasons. First, the development of the LNG export industry is likely to lead to rising domestic natural gas prices, as prices gravitate towards export-parity levels and become 'internationalised'. This means that gas transmission flows could switch from their present patterns. Rather than flowing directly from the most proximate fields to capital cities, gas will tend to flow north towards Gladstone. This means that certain gas transmission pipelines may experience falls in utilisation as other pipelines substitute for their erstwhile functions. The Moomba to Adelaide pipeline in particular could fall within this category, as potentially could the Moomba to Sydney pipeline.

Second, higher gas prices and flat electricity prices could encourage consumers to substitute towards electricity for domestic and other purposes. The pace of these changes will be subject to the long-lived and costly nature of energy appliances, but it remains a medium to long-term risk for both gas transmission and distribution networks. Transmission pipelines vulnerable to this effect could include the Moomba to Sydney pipeline and the Roma to Brisbane pipeline. Gas distribution networks in the warmer capitals could also experience similar risks over the same timeframes.

As noted above, both electricity and gas distribution networks have been relatively insulated from solar PV and other forms of micro-generation to date. These developments are in themselves unlikely to allow complete by-pass of at least electricity distribution networks in the foreseeable future This is because customers with micro-generation units typically still rely on electricity distribution networks to provide power outside daylight hours or as back-up on cloudy days. Further, most residential customers with solar PV units seek to inject surplus daytime power back into the network to supply other customers. As such, complete by-pass of electricity distribution networks is extremely unlikely to occur, even in the long run. Electricity transmission networks may face a greater risk from distributed generation than distribution networks. But once again, complete by-pass seems to be a long way off.

The extent to which these greater demand-side risks affect the respective networks depends in large part to the applicable regulatory arrangements.

Investment/expenditure and service risks

As noted above, we consider that in general, energy networks avoid many of the risks of investing too little or too much to meet actual demand: under the existing building block form of regulation, most if not all actual capital expenditure is ultimately rolled into the regulated asset base. Inadequate investment leading to supply shortfalls typically imposes much higher costs on consumers than on service providers. Nevertheless, this section focuses on some of the key differences in regulatory investment arrangements across different types of networks.

Electricity networks unlike gas networks are often obliged to invest to meet reliability standards. These standards include redundancy-based (also known as deterministic) planning standards, performance standards and customer service standards. This can give rise to the risk that electricity networks invest too little or too much to meet the relevant standards.

However, several points should be borne in mind.

- First, not all electricity networks are subject to deterministic planning reliability standards. Neither the Victorian transmission planner, AEMO, nor the principal Victorian electricity transmission business, SP AusNet, are subject to deterministic reliability standards.[119] Rather, AEMO is required only to plan the network in a manner that maximises net market benefits using its probabilistic planning approach.

- Second, even where deterministic planning standards apply, they can be somewhat high-level and vague. Interpretation and application of the standards may involve some judgment. For example, only the network itself may know whether an 'N-1' planning standard is being met at a particular location at a given time.

- Third, even where electricity networks fail to meet planning standards, the sanctions they face may be limited. Most deterministic planning standards are contained in jurisdictional planning documents or licenses. In some cases (such as in NSW[120]), the standards are legally binding. However, there are often no clear financial penalties for breaching planning standards and we do not consider that licence revocation is a credible threat.

Gas networks tend not to face the same obligations. However, as noted below, maintaining reliable supply of gas to existing customers is a permissible basis for justifiable new capital expenditure in gas pipelines.

Leaving mandated reliability standards to one side, the regulatory investment criteria for electricity and gas networks are fairly similar. Proponents of electricity transmission network investments above $5 million are obliged to apply the Regulatory Investment Test for Transmission (RIT-T), as developed by the AER. The AER is in the process of developing an equivalent test for distribution

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119 AEMC Reliability Panel, *Towards a Nationally Consistent Framework for Transmission Reliability Standards, Review – Final Report*, 31 August 2008, Table B.1., pp.171-172.

120 See AEMC, *Review of Distribution Reliability Outcomes and Standards, Final Report – NSW Workstream*, 31 August 2012, pp.14-15.

investment (the RIT-D). Both tests adopt a cost-benefit framework for the assessment of investment decisions, subject to the need to meet deterministic reliability standards. The NGR contains broadly similar provisions[121] governing new capital expenditure: expenditure is justifiable if it yields positive net economic benefits, offers positive incremental revenue to the service provider or is necessary for safety or reliability reasons (where reliability refers to continuing to meet existing demands).

Another point to note is that the regulation of electricity transmission and distribution networks provides for supplementary revenue caps to be established where 'contingent projects' are triggered. Contingent projects are large (>$30 million) projects that the network business may be required or choose to commence during a regulatory control period if a particular defined and pre-specified trigger event transpires.[122] This helps further manage electricity transmission networks' risks of needing to undertake large and unpredictable projects at short notice.

Electricity transmission networks are also subject to regulatory incentive schemes designed to reward or penalise the reliability or quality of their service provision. However, most of these 'service target performance incentive schemes' place a relatively small proportion of the networks' revenues at risk.[123] Distribution networks are also subject or intended to become subject to similar schemes.[124] However, as yet, the schemes do not apply all distribution networks, such as the NSW distributors. The NGR makes no provision for service incentive schemes to apply to gas networks.

Although the building block form of regulation insulates energy networks from much of the downside risk of over-investing due to over-estimating demand, there are some differences in how over-spending is managed under the capital expenditure incentive mechanisms in the gas and electricity Rules. These, as well as operating expenditure mechanisms, are discussed in more detail below in the section on input cost and volume risk.

Demand/revenue risk

As noted above, deviations in demand for network services from those expected at the time of a regulatory reset decision can affect the stability of an energy

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121 NGR 79.

122 NER 6A.8, 6.6A.

123 For example, the NER (6A.7.4) limits the maximum benefit or detriment from the electricity transmission Service Target Performance Incentive Scheme to +/-5% of regulated revenues. The recent electricity transmission decision for Powerlink limited the maximum benefit or detriment to +/- 1%, which is the minimum level permitted under the NER.

124 NER 6.6.2.

network's revenues and profits. The extent to which variations in demand affect the revenues and profits of an energy business also depends on the form of control applicable to the network business.

For electricity transmission, the NER specifies the form of control to be revenue-capping.[125] The requirements are more flexible for other types of energy networks. In particular, the NER allows the form of control for direct control services provided by electricity distributors to be any one of a range (or a combination) of options.[126] The AER has indicated recently that it is considering a move towards revenue capping for NSW electricity distribution businesses.[127] The NGR allows gas networks to nominate the form of control that ought to apply to them and limits the AER's discretion in this regard.[128]

If applied to electricity distribution businesses, the adoption of revenue-capping would further reduce those networks' exposures to volume/revenue risk. However, whether this would be profitable is unclear. During times of rising peak demand, such as through the mid-to-late 2000s, WAPCs tended to provide temporary windfall revenue gains. A move to revenue-capping going forward could be beneficial in an environment of peak demand and consumption now tending to undershoot forecasts. On the other hand, to the extent that electricity distribution networks have gained by over-forecasting peak demand and under-forecasting volumes, a move to revenue-capping could reduce the opportunities to exploit the regulatory process to increase profits.[129] We note that Ausgrid has opposed the adoption of a revenue cap on the grounds that a revenue cap would reduce its incentives to set efficient cost-reflective prices and reduce customers' incentives to engage in efficient demand management.[130]

On balance, while it is possible that a move to revenue-capping of electricity distribution networks could increase the instability of their revenues, it is unclear whether:

- The increase in volatility would be symmetrical and
- Profits would in general increase or decrease.

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125 NER, 6A.4.2(a)(1).

126 NER, 6.2.5.

127 AER, *Matters relevant to the framework and approach, ACT and NSW DNSPs 2014-2019, Discussion Paper*, April 2012; AER speaking points – AEMC demand workshop, 28 February 2013, p.5.

128 NGR, Part 9, Div 8.

129 AER, *Matters relevant to the framework and approach, ACT and NSW DNSPs 2014-2019, Discussion Paper*, April 2012, p.11.

130 Ausgrid, *Response to the Australian Energy Regulator consultation paper on Form of Regulation*, May 2012.

Therefore, it is difficult to contend that the various applicable and potential forms of control do or are likely to subject systematically different types of energy networks to volume/revenue risks.

5.2.2 Input cost and volume risk

Energy networks' costs to serve may vary due to either changes in the cost of inputs or the volume of required inputs. While we consider that the level of such risks for all types of energy networks is relatively low compared to other types of businesses, it is worth examining briefly how the regulation of different networks costs' differs.

Gas pipelines

Pipeline owners are able to add the cost of all 'conforming capital expenditure' to their regulated capital base. Conforming capital expenditure means expenditure that:

- Would be incurred by a prudent service provider acting efficiently in accordance with good industry practice to achieve the lowest sustainable cost (Rule 79(1)); and

- Satisfies at least one of the criteria in Rule 79(2), including that the expenditure has an overall positive economic value, provides incremental revenues in excess of costs in present value terms or is necessary to ensure safety, reliability or the continued provision of existing services.

This means that where gas network owners have overspent relative to their allowed forecast capital expenditure, but the overspend is found to be conforming capital expenditure, they only bear the cost of the overspend (being the return on and of the overspend) up to the end of the relevant access arrangement period. Beyond that time, customers bear the cost through an increase in the capital base, which flows through to reference service tariffs. Network owners are only exposed to the full cost of capital expenditures where they incur expenditure deemed to be non-conforming. We understand that the AER has not previously disallowed capital expenditure under this provision. However, in its final decision on the current Roma to Brisbane pipeline, the AER did not allow APTPPL to include the entire value of the Pipeline Management Agreement (PMA) buyout payment as conforming capital expenditure.[131]

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131 The AER approved $24.8 million as conforming capital expenditure rather than the $30.1 million proposed by APTPPL.

Where gas network owners have underspent relative to their allowed forecasts, they are entitled to keep the benefit of the return on and of the underspend until the end of the access arrangement period.

The NGR provides for capital and operating expenditure incentive arrangements to apply to gas pipelines to further encourage networks to reduce their costs. However, such arrangements are often not applied.[132]

Electricity networks

Ex post exclusion of capex

Following recent changes to the NER, the AER may now exclude certain amounts of capital expenditure from either an electricity distribution or an electricity transmission network's regulated asset base. The NER provides that, *inter alia*, where a network business has overspent relative to its capital expenditure allowance, and the AER determines that the overspend does not conform to the capital expenditure criteria and other provisions in the NER, the AER may exclude some or all of the overspend in accordance with the Capital Expenditure Incentive Guidelines.[133] The changes to the NER also provide the AER with the ability to exclude other amounts – namely related party margins and capitalised operating expenditure – from the roll forward of the regulated asset base.

The AER has indicated to date that it intends to rely primarily on the existing *ex ante* incentive framework to encourage electricity networks to undertake efficient capital expenditure. The AER is only likely to exclude inefficient capital expenditure above the permitted allowance where "there is a significant overspend and where the *ex post* assessment has uncovered clear cases of inefficiency or imprudent behaviour by the NSP."[134] Such an *ex post* assessment is likely to involve a four-stage process, with substantial scope for the network business to escape any penalty for over-spending.[135] This suggests that the risks to electricity networks from *ex post* reviews of capital expenditure are likely to be very limited.

Ex ante forecasting and incentive arrangements

In addition to the mandatory application of the RIT-T and RIT-D to significant capital expenditures prior to expenditures being incurred, electricity networks are

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132 For example, the recent AER determinations for APA GasNet and Envestra (Victoria) rejected the service providers' proposed incentive mechanisms.

133 NER S6A.2.2A and S6.2.2A.

134 AER, *Expenditure incentive guidelines for electricity network service providers, Issues paper*, March 2013, p.vii.

135 AER, *Expenditure incentive guidelines for electricity network service providers, Issues paper*, March 2013, pp.39-43.

subject to various *ex ante* incentives designed to promote efficient decision-making.

As required under the NER, the AER is in the process of developing or modifying guidelines for capital expenditure and operating expenditure forecasting and incentive schemes. However, any changes to such *ex ante* incentive arrangements are likely to be relatively minor.

In its Expenditure Incentives Issues Paper, the AER indicated that it proposes to:[136]

- Move from the current symmetric capital expenditure incentive arrangements which provide for networks to face an approximate 17-30% of increases and decreases in their expenditures to an asymmetric regime where networks enjoy a reward of 20-3% of underspend and incur a cost of greater than 30% of overspend.

- Make only minor changes to the operating expenditure efficiency benefit sharing scheme, which provide for networks to be exposed to approximately 30% of expenditure under- and overspends.

In its Expenditure Forecasting Issues Paper, the AER has proposed making greater use of benchmarking techniques in assessing networks' expenditure forecasts.[137] This may, at the margin, increase electricity networks' input cost/volume risks in the future. However, relative to non-energy network businesses, their input cost risks are likely to remain low.

Conclusion

Electricity networks appear to face and be likely to face offsetting exposures to cost/volume risk. While gas networks appear to face a slightly higher risk of having capital expenditures disallowed from inclusion in the regulated asset/capital base, electricity networks face stronger expenditure incentives and may face tighter expenditure forecasts. Accordingly, it is difficult to conclude that different types of energy networks face significantly different input cost risks.

5.2.3 Stranding/optimisation risk

Chapter 4 noted that regulatory stranding or 'optimisation' risks are fairly contained for Australian regulated energy networks. However, there are some minor variations between the different network types that are worth acknowledging.

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136 AER, *Expenditure incentive guidelines for electricity network service providers, Issues paper*, March 2013.

137 AER, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues paper*, December 2012.

The NGR provides for a gas network's assets to be removed from the regulated capital base in respect of assets that cease to contribute *in any way* to the delivery of pipeline services.[138] The AER may also require an access arrangement to contain a mechanism to enable costs of redundant assets to be shared as between the service provider and users. Importantly, the rules oblige the AER to consider the uncertainty that partial or entire asset removal from the capital base would cause and how this would uncertainty affect the network and customers. Redundant assets that subsequently become used and useful can re-enter the capital base in the same way as new facilities investment.[139]

This provision has applied to gas networks since prior to the promulgation of the NGR. It is based on a near-identical clause in the former National Gas Code,[140] although clause 8.27 also included the following condition:

> If a Reference Tariff does include such a mechanism, the determination of the Rate of Return (under sections 8.30 and 8.31) and the economic life of the assets (under section 8.33) should take account of the resulting risk (and cost) to the Service Provider of a fall in the revenue received from sales of Services or part of the Covered Pipeline.

This condition was not transposed into the original NGR in 2008 or any subsequent version of the NGR.

The NER provides for an electricity transmission network's assets to be removed from the regulated asset base where:

- The asset is dedicated to one or a small group of directly connected customers (eg aluminium smelters or other industrial plant); and
- The value of the asset is at least 410 million (indexed)

If the AER determines that:

- the asset no longer contributed to the provision of prescribed transmission services; and
- the transmission network has not adequately sought to manage the risk of redundancy by negotiating a prudent discount with the customer or agreeing an appropriate allocation of redundancy risks on post-2006 investments.

We also understand that the AER has not employed this mechanism to date.

Chapter 6 of the NER (which deals with electricity distribution) does not contain an equivalent provision.

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138 NGR 85.

139 NGR 86.

140 *National Third Party Access Code for Natural Gas Pipelines*, November 1997 (National Gas Code), clause 8.27.

5.3 Conclusion

In our view, there are some reasons to think that regulated gas transmission pipeline networks may be somewhat riskier than other types of regulated energy networks. However, this is not a strongly-held view.

Gas transmission pipelines are more heavily dependent on a relatively small number of large industrial customers than either gas distribution or electricity networks. With threats to some existing pipelines arising from new pipelines built to serve LNG processing and export facilities and relatively cheaper wholesale electricity prices, some gas pipelines face greater competition than electricity networks.

As gas networks governed by the NGR, gas transmission networks also seem to face similar (to-date theoretical) risks of regulatory asset stranding and perhaps stronger risks of having capital expenditure excluded from the asset base than electricity networks. On the other hand, gas networks appear to face – and are likely to continue to face – lower-powered capital and operating expenditure efficiency incentives than electricity networks. In particular, moves towards the use of benchmarking forecast expenditures perhaps combined with slightly higher-powered incentive schemes, which gas networks have tended to avoid to date.

6 Practical applications for our assessment of energy network risks

In the preceding Chapters of this report we have:

- identified a range of risks that might apply to regulated energy networks in Australia;
- explained how these risks may be affected by managerial action, and also by the regulatory framework in place; and
- discussed how these risks might differ as between regulated energy networks and unregulated firms, energy networks and water networks, and different types of energy networks.

In this Chapter we explain how the analysis so far may be used practically to evaluate the risks that should be compensated through the allowed rate of return.

6.1 Which risks are relevant to the allowed rate of return?

Thus far, our discussion has focused on total risks (i.e. the variance of returns or cash flows in respect of each of the risks identified). However, as McKenzie and Partington (2013) have explained, it is not total risk that matters when determining the appropriate allowed rate of return for regulated energy networks in Australia. Rather, it is **covariance risk** that matters.

Covariance risk is the **sensitivity (or correlation)** of the regulated firms' cash flows or returns to some wider factors (such as the market factor in the Sharpe-Lintner CAPM).[141] In other words, covariance risk represents the risk that investors actually price in to their assessments of the cost of capital for the business in question. By implication, there are certain risks (or certain quantities of total risk) that investors do not price in to their investment decisions because these can be diversified away. A clear insight from finance theory, which McKenzie and Partington (2013) make plain, is that only risks that cannot diversified away by investors should be compensated through the allowed rate of return.[142]

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141 In the Sharpe-Lintner CAPM, covariance risk is measured by beta. In other models, covariance risk is captured by the correlation coefficients that relate to the particular factors specified within the model. We do not presuppose that the Sharpe-Lintner CAPM is the only asset pricing model that is appropriate. To preserve generality, we use the broader term 'covariance risk', rather than beta, throughout the remainder of the report, when referring to the sensitivity of returns to a given factor.

142 To be precise, it is only the non-diversifiable risks faced by the **marginal** investor that matter in terms of the required rate of return.

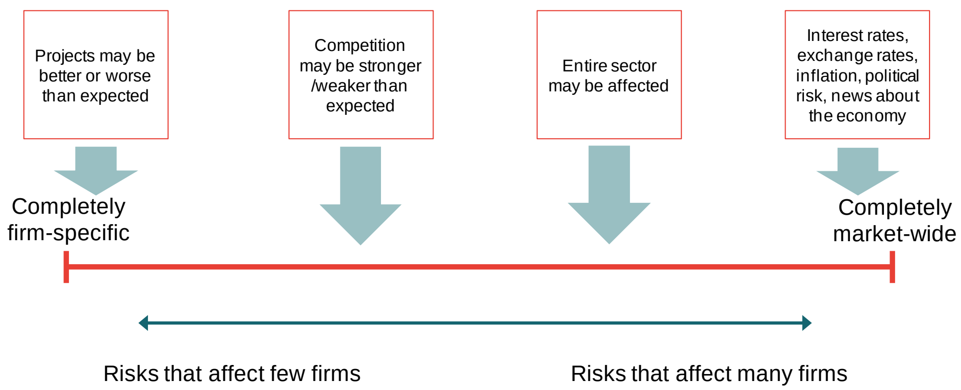
However, in practice it is not straightforward to delineate between diversifiable and non-diversifiable risks. In addition, the definition of covariance risk varies between different asset pricing models. These two things mean that it is impossible to say, a priori, and with certainty, which of the risks identified in earlier chapters really matter for the purposes of determining the allowed rate of return, and by how much they matter. As we discuss in the section 6.2, this must be determined empirically.

6.1.1 Challenges in distinguishing between diversifiable and non-diversifiable risks

It is very common for practitioners to make binary distinctions between different types of risk as being purely diversifiable or purely non-diversifiable. However, in practice no such bright lines exist. For example, it may be tempting to argue that because regulatory risk relates to only certain industries or groups of firms, this risk must be diversifiable and therefore irrelevant to the cost of capital for these firms. However, section 2.1.8 presented examples of studies that find empirical evidence that regulatory uncertainty can affect systematic risk (per the CAPM), and therefore the WACC.

A more useful way of thinking about the risks that regulated businesses actually face is in terms of points along a spectrum, as represented in **Figure 13**.

Figure 13. Spectrum of risks



Adapted from: Damodaran (2001), Corporate Finance: Theory and Practice, chapter 6.

Located at the extremes of this spectrum are purely diversifiable risks and purely non-diversifiable risks. However, it is unusual for risks faced by companies to lie precisely at one extreme or the other.

An example of a very firm-specific risk could be the risk that a real project (e.g. a R&D opportunity, or an upgrade/extension to an existing network to serve uncertain future demand) available to only one firm in the industry turns out to be more or less successful than expected. From the perspective of the marginal investor, this risk would probably be largely diversifiable because it affects only one firm. However, it is impossible to say ex ante that the risk is *completely* diversifiable because the unanticipated success or failure of the project could have its origins in factors beyond the control of the firm, and these factors may also impact on other firms (albeit in different ways).

Slightly further along the spectrum may be risks arising from competition between a small number of firms (e.g. a few firms may be in a race to win a supply contract, but only one of these competitors will be successful). An equity investor may largely eliminate this risk by holding shares in a number of competing businesses. Again, though, the success or failure of individual competitors may depend, at least partly, on macroeconomic factors that also influence the performance of the economy more generally. This element may be non-diversifiable, even with a very wide investment portfolio.

Further still to the right along the spectrum may be risks that affect a whole industry (e.g. the change to an industry-wide regulatory regime). Again, these risks may be diversified partially. However, the underlying source of the risks affecting the industry in question may be more economy-wide in nature. If that is the case, even risks that appear to be industry-specific could turn out to be difficult to diversify.

Market-wide risks, which are the most difficult to diversify, are risks that affect all assets in the economy, although the extent of exposure to these risks may vary between assets. These risks depend on macroeconomic factors, such as exchange rates, interest rates, inflation, government policies and the state of the economy more generally.

What this shows is that it is not feasible to assess every risk one at a time to determine if and by how much it should be reflected in the rate of return. We have no framework to translate each individual risk into a discrete component of the rate of return. However, a firm's exposure to all the risks it faces is reflected ultimately in the variability of its cash flows or returns over time. As discussed by McKenzie and Partington (2013), there are models that allow the quantification of risk that does matter in terms of the rate of return by making use of the information contained in the variation in cash flows/returns over time.

6.1.2 Model uncertainty

Another difficulty that prevents a definitive, ex ante identification of which risks matter for the allowed rate of return, is that the definition of covariance risk depends on the asset pricing model used. McKenzie and Partington (2013) survey a number of different models that may be applied to estimate the cost of capital. Some are single-factor models (e.g. the Sharpe-Lintner CAPM), and some are multi-factor models (e.g. the Fama and French three factor model). In some models, certain factors are considered to be important explanators of the variation in asset returns. In other models, those same factors may matter to a lesser extent, or may not matter at all, because other factors are regarded as relevant explanators.

In short, the risks that are relevant to an assessment of investors' expected returns depends on the asset pricing model adopted. Each model has weaknesses as well as strengths. Financial economists have, to date, been unable to identify a single model that provides a 'perfect' answer to the question of which risks really matter to investors. Hence, there is uncertainty over the 'true' model that describes the risk-return relationship that investors actually care about. In the face of such model uncertainty, it is sensible to employ evidence from a range of models. This means, necessarily, that we cannot specify in advance which risks are priced by investors and which are not.

6.2 Operationalising the measurement of risk

In our view, the question of which risks should be compensated through the allowed rate of return cannot be answered purely analytically; it is largely an empirical question. This section sets out recommendations on how the AER could operationalise the measurement of the relevant risks, making use of the analysis provided so far in this report. The approach that we present here mirrors the approach to the assessment of risk used in commercial valuation exercises.

As discussed by McKenzie and Partington (2013), it is covariance risk (i.e. the sensitivity/correlation of returns to the relevant factors), rather than total risk, that ought to be reflected in the allowed rate of return. In order to measure covariance risk empirically, good data on the returns associated with the business in question are required. 'Good' data generally means price information on assets that:

- reflect closely the risks and opportunity costs associated with the investment in question; and
- are traded over a reasonably long period and are sufficiently liquid as to reflect relevant market information adequately.

In respect of these criteria, the networks regulated by the AER pose two important data challenges:

- Firstly, as noted in Chapter 4, very few of the owners of the regulated networks issue equity that is traded on stock exchanges.[143] Hence, the returns related to most of the networks regulated by the AER cannot be calculated directly.

143 However, a number of the networks may indeed issue traded bonds, which could be used to inform assessments about the cost of debt.

- Secondly, those network owners that do issue traded securities tend to invest in different types of regulated energy networks, and in some cases also in unregulated assets. Thus, the returns data that do exist may reflect the risk profiles of a variety of activities that may not match the risk profile of the regulated assets in question.

These difficulties are not atypical in many commercial investment appraisal exercises. It is rare to have good, direct returns data on many commercial investments/assets that firms and investors may be interested in valuing. In such circumstances, the approach taken typically is the so-called **comparator approach**. The comparator approach (or variants of it) has also been adopted widely by regulators around the world, including by the AER in Australia.

The comparator approach involves three key steps:

1. Identify a group of comparator firms that share similar risk characteristics to the business of interest, for which good market data do exist.
2. Apply an asset pricing model or models to the comparator data to estimate the level of covariance risk exposure faced by the comparators.
3. Translate the estimate of covariance risk for the comparators into a suitable estimate for the business of interest.

We discuss each of these steps in turn.

6.2.1 Identification of suitable comparators

The first step under the comparator approach is to identify an appropriate set of comparator firms for which good market data exist. The suitability of the comparators should be determined by the closeness of their risk characteristics to the business of interest — in this case, the benchmark efficient entity or entities, however the AER may choose to define those terms.

In Chapter 4 we identified the characteristics and key risks of regulated energy networks in Australia. The most suitable comparators would be firms that share closely those characteristics and risks. Hence, the AER could use the results from Chapter 4 to inform its selection of appropriate comparators.

Naturally, the most suitable comparators for the purposes of estimating the cost of equity are listed companies in Australia that have significant ownership of regulated network assets.[144] These firms share the key risks and characteristics

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144 Ideally, of the listed companies that own regulated energy networks, those that also have significant ownership of unregulated businesses should be excluded from the comparator group. This is because these businesses could have quite different risk profiles to the regulated assets, which, if so, could distort the estimates of covariance risk exposure faced by the networks regulated by the AER. However, applying too aggressive a filter to remove the influence of unregulated activities could reduce the sample to size that is unworkably small. Hence, a sensible trade-off needs to be made

identified in Chapter 4, and so are a good starting point for the empirical estimation of covariance risks.

As noted earlier, the number of such listed companies in Australia is quite small at present. Given the problem of small sample size, it may be possible to improve the quality of the estimates by considering overseas evidence as well. There are a number of listed companies abroad that own regulated energy networks engaged in activities that are similar to those performed by regulated energy networks in Australia. However, these companies may be less ideal comparators than Australian peers because:

- The regulatory frameworks governing overseas networks may differ from the framework applied by the AER. Regulated companies in the UK and certain parts of Europe may generally be closer comparators in this regard than North American networks.

- Companies overseas may face different exposures to macroeconomic (e.g. refinancing, inflation and exchange rate risks) and other country-specific (e.g. political) risks.

- There could even be scope for differences in competition risks (as noted in section 2.1.6, some competition between gas pipelines has emerged in the US, whereas competition to a similar extent has not materialised in Europe or in Australia).

These factors need not rule out the use of overseas comparators. They simply mean that overseas evidence should be used carefully. For instance, estimates based on overseas data could be used as cross-checks on estimates based on domestic data, rather than pooling these estimates together.

In addition, it may be useful to consider evidence on other regulated, non-energy networks, such as regulated water companies. As explained in Chapter 4, there are no listed water companies in Australia. Therefore, any such evidence must necessarily be obtained by reference to overseas companies (e.g. from the UK or the US).

In a recent submission to the AER about our draft report, the Major Energy Users Inc (MEU) stated that:

> The approach used by Frontier in its report provides the AER with little usable information on which to assess the comparative risks faced by NSPs. The most important aspect that the AER needs to know is how to recognise the risks faced by NSPs compared to the market average, recognising the market average (market risk premium) is the benchmark used by the AER to set the return on equity. The

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between adequate sample size and comparability of the firms in the sample to the business regulated by the AER.

> absence of any comparative data to firms in competition and quantification of the risks identified (and allowing an offset of the benefits of the regulatory regime provides) leaves the AER in no better a position than it was without the report.

We agree with MEU that the most important question for the AER is how to quantify the relevant risks of the networks it regulates against some benchmark (which, in certain asset pricing models is the market). As explained in section 6.1, the assessment of these risks should be done empirically rather than purely analytically. Our analysis in this report provides the AER with a conceptual framework for identifying suitable comparators that may be used to estimate empirically the risks that should be compensated through the WACC.[145]

6.2.2 Application of asset pricing models

Once a suitable comparator group has been identified, and data on the firms have been collected, the next step is to apply an asset pricing model, or models, to the data to obtain an estimate, or estimates, of covariance risk for each of the comparators. McKenzie and Partington (2013) have surveyed the various models that could be employed and have discussed the practicalities involved in implementing them. It is worth reiterating the point made above that, in the face of model uncertainty, it is sensible to rely on evidence from a range of models (to the extent it is practical/feasible to implement a variety) rather than rely exclusively on a single model. It is common for regulators overseas to use the Sharpe-Lintner CAPM as their primary model, and to use other models as cross-checks on the CAPM's estimates. We think that approach is reasonable.

6.2.3 Translation of estimates for the comparators into suitable estimates for the business of interest

Once estimates of covariance risk for each of the comparators have been obtained, the final step is to translate these estimates into a suitable estimate for the business of interest. The usual approach is to average across the comparator estimates to obtain an 'industry' estimate and then apply that average as an estimate for the business in question.

However, it is important to recognise that it is generally very difficult in practice to identify a comparator group that matches perfectly, or even very well, the characteristics and risks of the particular business of interest. Therefore, it may be necessary to adjust the industry estimate of covariance risk up or down in order to obtain a better estimate for the business in question.

The way to decide on the adjustment would be to:

145 Our brief was to provide the AER with qualitative, rather than quantitative, advice on this matter.

- First, postulate a hypothesis about the difference in the characteristics between the comparators and the business in question;
- Next, test this hypothesis empirically; and
- Finally, use that empirical evidence to adjust the industry estimate.

For example, Chapter 5 suggested that there are some reasons to think that regulated gas transmission pipeline networks may be somewhat riskier than other types of regulated energy networks (though we could not conclude definitively that this is the case or that any difference is material). This may be formalised as a testable hypothesis: *regulated gas transmission pipeline networks are riskier than other types of regulated energy networks*.

To test this hypothesis, we might gather estimates of covariance risk for gas pipeline networks, and compare these to estimates of covariance risk for other energy networks to see if a material difference may be detected. In practice, we would have to look at overseas data in order to test this hypothesis empirically as there are insufficient data in Australia with which to do so. Sample sizes overseas are sufficiently large to partition between companies that have significant regulated gas pipeline activities and those that have significant regulated non-pipeline (i.e. gas distribution and electricity network) activities.

It is important to keep in mind that, in testing this hypothesis, we are interested not so much in the absolute level of covariance risk for each type of network as the relative difference in covariance risk between different networks. Hence, provided that the comparison between networks are restricted to companies operating in roughly the same geographic region (e.g. US networks are compared only to other US networks; European networks are compared only to other European networks), the country-specific factors raised in section 6.2.1 should have minimal effect on the *relative* risk comparisons.

If the empirical evidence suggests that the hypothesis cannot be rejected, then the average difference in covariance risk between gas pipeline and non-pipeline networks could be used to adjust industry estimate up. If the hypothesis is rejected, then the industry estimate would require no adjustment.

6.2.4 A comparator approach to estimating the cost of debt

The comparator approach described above can be applied to estimate the covariance risks relevant to the cost of equity, and this is done commonly by finance practitioners, companies and regulators. As noted by McKenzie and Partington (2013), the regulatory assessments of the cost of debt usually focus on promised, rather than expected, returns. Therefore, the variety of asset pricing models they survey (and which may be used as part of the comparator approach) are not used typically to determine the cost of debt for regulatory purposes.

However, for completeness, we note that a comparator approach of the kind described above could, in principle, be used to determine the cost of debt — in particular, the debt premium employed in the calculation of the cost of debt. The steps involved would be the following:

1. Compile a sample of traded debt (bonds, typically) that have comparable characteristics to the debt issued by the business in question. Here, once again, the business in question would be the benchmark efficient firm(s).
2. Calculate the debt premium for each of these comparator bonds by subtracting from the redemption yield a suitable estimate of the risk-free rate.
3. Translate this debt premium into an estimate for the business in question by averaging across the debt premiums paid by the comparators.

Steps 2 and 3 are straightforward to implement. Some criteria that could be used for selecting comparator bonds in step 1 would be their similarity to the bonds issued by the business in terms of the following characteristics:[146]

- country of issue;
- credit rating;
- tenor;
- liquidity (i.e. similarity in bid-ask spreads); and
- size of issuance.

146 See, for example, Cooper, I. (2013), *Evidence concerning whether there is a premium in the WACC of Phoenix Natural Gas Limited relative to the WACC of mature GB utilities*, May.

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