Economic principles for deciding on the appropriate form of regulation for the South West Queensland Pipeline

Report for Gilbert + Tobin

March 2024

INCENTA

ECONOMIC CONSULTING

Contact us:

Incenta Economic Consulting
Unit 1, 19-35 Gertrude Street
Fitzroy, Victoria, 3065
Telephone: +61 3 8514 5119
Website: www.incenta.com.au

Disclaimer:

Table of Contents

Tables and figures

1. Introduction and summary

1.1 Our brief and authorship

1.1.1 Brief

We have been engaged by Gilbert + Tobin as solicitors for APA to make comment on certain matters the AER raises for consultation in relation to whether it should make a scheme pipeline determination for the South West Queensland Pipeline (SWQP). The specific questions that we have been asked are as follows:

> *We are seeking a report setting out your expert opinion on the relevant economic principles for deciding on the appropriate form of regulation for the SWQP, including:*
>
> *(a) how the potential effect of regulating the SWQP as a scheme pipeline or non-scheme pipeline should be assessed; and*
>
> *(b) the appropriate economic framework for assessing the costs likely to be incurred by an efficient service provider, current and prospective users, and end-users under different forms of regulation.*
>
> *Relevant background information on the SWQP is set out at Appendix A.*

Our full letter of instruction is appended to this report as Appendix B. We discuss the context for these questions, and their meaning within that context, in more detail below.

1.1.2 Authors

This report has been prepared by Jeff Balchin and Dr Ray Challen. Both authors have several decades of experience with applying economic principles to the regulation of infrastructure assets, as well as a deep experience with gas pipeline regulation issues specifically. For most of his career, Jeff has been an economic consultant, and has advised a wide range of clients spanning regulators, governments, asset owners and major customers across most of the key infrastructure sectors. Jeff also had a central role in the creation of the original National Third Party Access Code for Natural Gas Pipeline Systems (National Gas Code) and its early application to the gas sector. Ray's experience has been similar, in that he has worked for a considerable time as an economic consultant advising across a similar breadth of clients and sectors as Jeff; however, in addition, Ray headed the Western Australian Public Utilities Office for a period, and most recently served as a governing body member of the Western Australian Economic Regulatory Authority.

The curricula vitae of Jeff and Ray are appended to this report as Appendix C.

We have reviewed the requirements for expert reports set out in the Federal Court's Expert Evidence Practice Note (GPN-EXPT) (Practice Note), which includes the Harmonised Expert Witness Code of Conduct (Code), and we have prepared our expert report in accordance with the requirements of the Practice Note and the Code.

1.2 Background

National regulation of gas pipelines was introduced in the late 1990s under the then National Third Party Access Code for Natural Gas Pipeline Systems. Regulation under the Code comprised ex ante price regulation and was applied to a limited set of "covered" major gas transmission pipelines and distribution networks.

Reviews of the access regime in the early 2000s led to the regulatory regime being amended to include "light-handed" regulation comprising a negotiate-arbitrate framework with obligations for information disclosure by the pipeline service provider. Coverage decisions for pipelines then comprised a two-stage decision of (i) coverage and (ii) the form of regulation to apply.

The coverage decision has subsequently been abolished from the regulatory regime so that the decision on applying regulation to a pipeline comprises only the form of regulation. The current regulatory framework for natural gas pipelines under the National Gas Law and National Gas Rules allows for two forms of regulation to be applied to pipelines.

- Scheme pipelines, for which regulation includes ex ante (reference tariff) price regulation.
- Non-scheme pipelines, for which regulation comprises requirements for information disclosure and a negotiate-arbitrate framework for determining the terms and prices for pipeline services.

"Non-scheme pipeline" is the default designation of a pipeline that was not a covered, fully regulated pipeline prior to March 2023 when relevant amendments to the National Gas Law came into effect. The historically fully regulated pipelines became scheme pipelines.

A non-scheme pipeline may become a scheme pipeline by:

- election by the service provider of the non-scheme pipeline,[1] or
- the AER determining that a non-scheme pipeline is to become a scheme pipeline, either on application by any person to the AER, or on the AER's own initiative (a "scheme pipeline determination").[2]

A scheme pipeline may become a non-scheme pipeline by the AER making a "scheme pipeline revocation determination", which may also occur on application by any person to the AER, or on the AER's own initiative.[3]

The AER refers to either type of determination as a form of regulation determination.[4]

A form of regulation determination by the AER is governed by principles set out in the NGL that the AER refers to as a "regulatory determination test".[5] The AER has published the Pipeline Regulatory

1 National Gas Law, section 95
2 National Gas Law, section 92
3 NGL, section 97
4 AER, March 2024, Form of Regulation Review: South West Queensland Pipeline Discussion Paper, p1.
5 NGL, section 112

Determinations and Elections Guide[6] on how it intends to undertake regulatory determination tests, including scheme pipeline determinations.

The AER has commenced a self-initiated form of regulation review of the South West Queensland Pipeline (SWQP) as the first of a series of self-initiated form of regulation reviews the AER is planning to undertake over the next several years.[7] The AER has published a discussion paper for the purposes of consultation on this review.[8]

In this report, we address several of the matters on which the AER is seeking views, in particular:

- the AER's intended approach making a form of regulation determination and its intended application of the various criteria and factors set out in the NGL
- trends and the future outlook for the gas market and implications for assessing the costs and benefits of scheme pipeline regulation
- the potential effects of scheme pipeline regulation on the prices charged for SWQP services, and
- the potential effects of scheme pipeline regulation on efficient investment in the SWQP.

In addressing these matters, we have had regard to the following matters of context for the SWQP.

- An increase in demand for pipeline services in the short term. In the near term, there is expected to be an increase in demand for pipeline services from the SWQP as gas-fired electricity generation increasingly complements renewable generation and there is a transition away from coal fired generation. This will comprise an increase in pipeline throughput as well as increasing demand for ancillary services such as peaking and storage.
- Medium to long term Demand risk. As a result of climate change policies and advances in renewable electricity generation technologies, there is likely to be a substantial decline in demand for natural gas over coming decades and well within the operational lives of existing and any new pipeline assets. However, the timing of this decline is uncertain.
- Potential requirements for significant investments in pipeline capacity. While total pipeline throughput is likely to decline, peak demand may increase as the role of gas-fired electricity generation changes to a greater amount of peaking generation and potentially requiring investment in pipeline capacity to meet this demand, particularly addition of compression.
- The time frames of major pipeline investments are short, typically in the order of two years from investment decision to commissioning for the investments in compression.
- There is a change in contractual preferences of pipeline users, with a decreasing willingness to enter long term contracts.

---

6 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide

7 https://www.aer.gov.au/news/articles/communications/south-west-queensland-pipeline-undergo-form-regulation-review

8 AER, March 2024, Form of Regulation Review: South West Queensland Pipeline Discussion Paper

1.3 Summary of conclusions

1.3.1 Criteria for determining whether to make a scheme pipeline determination

The AER's Pipeline Regulatory Determinations and Elections Guide[9] and current discussion paper[10] suggest that the AER has interpreted the principles for making scheme pipeline determinations as requiring an economic framework to be applied consistently with, amongst other things, the National Gas Objective. The National Gas Law criteria for a determination essentially require the AER to weigh up the relative costs and benefits to service providers, pipeline users and gas end-users of applying scheme regulation (i.e., ex ante price setting under Part 9 of the NGR) versus the pipeline remaining subject to non-scheme regulation (i.e., the negotiate-arbitrate regime supported with information disclosure).

We note, however, that the AER's description of the analysis it will undertake does not focus on economic costs and benefits.

- The AER indicates that its analysis will be qualitative rather than quantitative and that it will not attempt to quantify the full value of the benefits and costs under each form of regulation. We contend that a qualitative analysis is insufficient to meet the requirements of the NGL and would be a disproportionately simple level of analysis relative to the potential economic value at stake if the SWQP is improperly regulated.

- The AER gives substantial attention to whether a scheme pipeline determination would facilitate access to a pipeline and the potential "out of pocket costs" that might be incurred – or saved – by the pipeline service provider, pipeline users and gas consumers. However, the AER gives only cursory attention to potential "economic" costs and benefits of scheme pipeline regulation, including potential effects on efficient pipeline investment, as would be required in assessing consistency with the National Gas Objective. In our view, the potential for applying scheme pipeline regulation to the SWQP to deter efficient investment should be a central consideration for the AER, presenting a potential economic cost to either or both pipeline users and gas consumers.

Inadequate consideration of the risk to investment

Considering the potential long-term economic costs for pipeline users and gas consumers has particular significance in the context of medium to long term demand uncertainty and risks of asset stranding. In this report we describe the risks of capital under-recovery where there is material demand uncertainty, and we explain why the reference tariff regime for scheme pipelines does not adequately address the risk. We then explain why applying the reference tariff regime in a situation of substantial medium to long term demand risk may result in regulatory outcomes contrary to the revenue and pricing principles of the National Gas Law, erode incentives for investment contrary to the National Gas Objective and to the interests of pipeline users and gas consumers.

9 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide

10 AER, March 2024, Form of Regulation Review: South West Queensland Pipeline Discussion Paper, pp8, 9.

Difficulty with establishing the effects of scheme pipeline regulation

The AER has signalled that, when forming a view on the likely effect of a change to scheme pipeline regulation:

- it will consider whether there has been an exercise of market power historically, including whether monopoly rents have been earned, referencing the ACCC's comments in this regard,[11] and
- that a central consideration with deciding whether to make a scheme pipeline determination is to compare the prices for pipeline services that would be expected under scheme regulation to the prices that would otherwise prevail.[12]

Attempting to identify market power from historical returns is fraught

The AER has referenced the ACCC's comments that it considers there to be evidence of historical excess returns by the SWQP. The ACCC's findings were based principally on the proposition that a monopoly rent would accrue where historical costs are over-recovered. The historical recovery of capital costs is derived as the excess of revenue over operating expenses and a reasonable return on capital.

The AER should be aware that there are several material shortcomings with the ACCC's method for determining a monopoly rent.

At a practical level, this method counts any benefit from efficiency gains as a recovery of capital (which is an error).

Moreover, for the current context, the method would need to:

- be applied with an assumed cost of capital that is relevant to a pipeline company that is operating in a competitive market, otherwise the test will be biased to a finding of excess returns,[13] and
- include an allowance for stranded asset risk.

We also note that alternatives to calculating the historically recovered cost – such as through using accounting depreciation as a proxy for recovered capital – are even more fraught. It is almost certain that accounting depreciation will overstate the extent of capital recovery that an infrastructure firm in a competitive market would have received under a sensible tariff policy.

---

11 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, pp.13-14.

12 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, p.24.

13 It may be that using a cost of capital assumption that is appropriate for a regulated monopoly would suggest that excess returns have been made, whereas using a competitive pipeline cost of capital would suggest that returns have been normal. In this case, the test would not be able to discern whether or not excess returns had been made (i.e., it would be indeterminate).

Prices in competitive markets reflect forward-looking factors, not historical capital recovery

Defining monopoly rents in terms of historical capital recovery is inconsistent with how competitive markets work. In a competitive market, firms do not mark down the value of their assets as revenue is received and then reduce charges as capital is recovered. Investments are made based on forecasts of the future, and pricing and operating decisions are made with reference to forward-looking factors. The forward-looking factors include the capital costs that would be incurred by a new competitor entering the market, and not any historical record of capital costs and capital recovery.

The more conceptually accurate method of determining whether excess returns are being made is therefore to compare the incumbent's prices against those that allow a hypothetical (efficient) new entrant to recover its costs, including a commercial return. This test (the "hypothetical competitive new entrant test") derives the predicted conditions of long-run equilibrium in a competitive market. This is the theoretical basis for the "depreciated optimised replacement cost" (DORC) asset valuation method. Again, when applying this test, the commercial rate of return that is applicable to a pipeline operating in a competitive market should be applied.

Even so, there is wide recognition in economics that markets may never reach long-run equilibrium or stay there for long if they do. This makes it difficult to infer whether market power exists from profit outcomes, but more specifically means that such a finding requires a substantial and enduring departure from normal conditions, and that cannot be explained otherwise (e.g., reflecting the relative efficiency of the firm in question).

Comparison against the counter-factual of scheme pipeline regulation

It will be a complex exercise to form a view on how scheme pipeline regulation would affect prices. This will effectively require a view to be taken on the key decisions the AER will be required to make if scheme pipeline regulation is imposed, but before the necessary analysis and consultation has been undertaken. Moreover, the outcome that may be reached for many decisions is far from obvious.

- One of the decisions the AER will need to pre-empt is the value that may be set for the initial capital base. For assets that are part way through their lives this, in our view, is of the most difficult of regulatory issues, which stems from the fact that economic principles do not provide an unambiguous answer. To the extent that the old section 8.10 of the National Gas Code would need to be applied, then this would require, amongst other things, a consideration of:
  - an estimate of the "depreciated optimised replacement cost" of the pipeline
  - the "actual capital cost of the Covered Pipeline" less the "accumulated depreciation for those assets charged to shippers (or thought to have been charged to Users)"
  - "the basis on which Tariffs have been (or appear to have been) set in the past", and
  - "the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase".
- In addition, the AER will need to consider how it will apply the available tools under the National Gas Rules for scheme pipelines to manage asset stranding risk. We conclude in this report that the only "tool" that is available for this task for scheme pipelines – advancing depreciation to the

point where no material stranded asset risk remains – is likely to require cost recovery to be much more front-ended than may occur under commercially negotiated prices. It is thus plausible that scheme pipeline prices may be materially higher than the counterfactual of negotiated prices in the near term if scheme pipeline regulation is applied. If the AER does not adequately deal with stranding risk in its assumptions about possible reference tariffs and if this risk is otherwise being reflected in un-regulated pipeline prices, then the "with and without regulation" analysis of prices may not be a proper comparison.

Other comments on the legislative criteria

We also note that it is essential for the AER to undertake its assessment of the costs of making a scheme pipeline determination in the specific context of the pipeline being considered. In relation to the SWQP, we observe that:

- *Network externalities / economic interdependencies* – as the Expert Panel observed when recommending the form of regulation factors, the technical characteristics of gas transmission pipelines permit different parts of the grid to be operated independently, which makes competition for parts of the network feasible without material loss of efficiency.[14] This contrasts with the technical characteristics of electricity transmission, where substantial efficiencies arise from the joint operation of a large network. The AER should conclude that there are no material economic externalities in gas transmission that may present an additional barrier to entry (i.e., in addition to the barriers that may be created by economies of scale and sunk costs), and that competition in gas transmission is substantially more feasible than in electricity transmission (or, applying the same reasoning, competition in gas transmission is substantially more feasible than in gas distribution).

- *Countervailing market power and effectiveness of the threat of arbitration* – APA's counterparties include the very large retailers, including AGL and Origin Energy. The size of these parties, and the concentration of their interests, provide these parties with the means and motivation to avail themselves of all options to mitigate APA's market power. We note that this countervailing power for non-scheme pipelines is substantially enhanced under the gas regulatory regime as it now stands as the default regulatory regime for non-scheme pipelines is not no regulation, but rather a negotiate-arbitrate regulatory regime with streamlined processes and supported with substantial information disclosure. Our view is that the default non-scheme pipeline regime is an effective and fit-for-purpose regulatory regime for the SWQP.

1.3.2 Issues with cost-based regulation with uncertain demand

The medium to long-term demand risk facing gas pipelines should be a matter of particular concern to the AER in assessing the effects of the alternative forms of regulation on incentives for investment and the economic costs and benefits of regulation.

Substantial challenges exist with applying cost-based regulation to infrastructure in situations where there is material uncertainty over the time path of demand decline and the period over which investment is recoverable.

[14] Expert Panel on Energy Access Pricing, April 2006, Report to The Ministerial Council on Energy, pp.48-49.

- The regulatory regime of ex ante price regulation that applies to scheme pipelines was designed in the 1990s under premises of indefinite use of pipelines and constant or increasing demand. Depreciation allowances in cost-of-service calculations have typically been calculated by straight light depreciation over assumed technical lives of the assets, including an assumed life of principal pipeline assets in the order of 70 years. Capital recovery over these long periods has recently become a matter of concern to service providers.

- The difficulties with applying cost-based regulation to pipelines with long term demand uncertainty was canvassed extensively in the mid-2000s as an element of reviews of the Third Part Access Code for Natural Gas Pipeline Systems, including by the ACCC,[15] Productivity Commission,[16] the Ministerial Council on Energy,[17] and an Expert Panel appointed by the Ministerial Council on Energy.[18] Amongst other matters, the reviews addressed the question of whether pipeline regulation under the Gas Code generated the necessary incentives for pipeline investment in situations where demand is uncertain. The uniform conclusion of the reviews was that demand uncertainty was not able to be adequately addressed under the reference tariff regime by either bringing forward depreciation, compensating for stranding risk in the regulated rate of return, or using longer regulatory periods. Rather than attempting to modify the national gas regime to attempt to deal with this issue in cost-based regulation, the regime was instead changed so that reference tariff regulation was unlikely to be applied to pipelines with material demand risk.[19]

1.3.3 The current National Gas Regime compounds the potential for scheme pipeline regulation to deter efficient investment

The reference tariff regime applied to scheme pipelines is highly codified and amplifies the stranding risk that will deter efficient investment.

Most importantly, the only tool that is available to the AER to address long term demand uncertainty is to advance depreciation to reduce or eliminate stranding risk.

- In the case of the SWQP, advancing depreciation is likely to be insufficient to address the potential for stranded asset risk, leaving a very real risk that efficient investment may be deterred.

- Furthermore, using depreciation to manage (i.e., remove) stranded asset risk would be likely to result in regulated prices that are excessively "front-ended" compared to commercially negotiated prices, to the detriment of end-users.

---

15 ACCC, June 2002, Draft greenfields guideline for natural gas transmission pipelines.
16 Productivity Commission, 11 June 2004, Review of the Gas Access Regime.
17 Ministerial Council on Energy, May 2006, Review of the National Gas Pipelines Access Regime: Decision.
18 Expert Panel on Energy Access Pricing, April 2006, Report to The Ministerial Council on Energy.
19 There were four changes to the national gas regime subsequent to these reviews that combined to make it unlikely for pipelines subject to material demand risk to be subject to ex ante price regulation: (i) the test for coverage (i.e., whether any regulation applies) was raised; (ii) the option was introduced for pipeline proponents to seek a binding determination before construction that a pipeline would not pass the test for coverage for a 15 year period (and a 15 year exemption of price regulation was also introduced for pipelines bringing gas from other countries); and (iv) the light-regulation option was introduced.

In addition:

- The potential for "redundant capital" to be removed at the AER's discretion is a further substantial downside risk, for which compensation would be required to preserve incentives for investment, but which is not certain under the scheme pipeline regime.

- The procedural requirements and timeframes for securing regulatory approval of new investments are unlikely to be sufficiently timely to support the emerging needs of the market.

- Scheme pipeline regulation will inevitably place constraints around the speed with which pricing can be modified to keep pace with movements in the market, leaving the regulated business vulnerable to under-recovery.

1.3.4 Default of "negotiate-arbitrate" with information disclosure is a fit-for-purpose regulatory regime

We present the argument that the negotiate-arbitrate regime that already exists under the NGL and NGR for non-scheme pipelines is a better form of regulation for pipelines where investment is required in a context of substantial demand uncertainty. The negotiate-arbitrate regime provides greater flexibility for service providers in pricing of services and managing time paths of revenue commensurate with achieving recovery of capital and maintaining incentives for investment.

We consider that a proper consideration by the AER of the economic costs and benefits of a scheme pipeline determination for the SWQP would lead to the same conclusion.

2. Criteria for determining whether to make a scheme pipeline determination

2.1 Legal scheme and AER guidance

A scheme pipeline determination by the AER in respect of the SWQP would have the effect of elevating the form of regulation for the pipeline from the current negotiate-arbitrate regime combined with substantial information disclosure obligations to formal ex ante price control.

The criteria the AER is required to apply when deciding whether to make such a determination are set out in section 112 of the NGL.

The principal criteria for a determination are the effects of scheme pipeline regulation compared to non-scheme pipeline regulation on:[20]

- the promotion of access to pipeline services, and
- the costs that are likely to be incurred by an efficient service provider and users (i.e., shippers) and the likely costs of end-users.

When applying these criteria, the AER is further required to have regard to:[21]

- the national gas objective
- the form of regulation factors, and
- any other matter the AER considers relevant.

The AER has provided guidance on what it will consider when applying these criteria. The AER's interpretation of the overall import of the criteria is as follows:[22]

> *The regulatory determination test requires the AER to consider how effective each form of regulation (i.e. full and light regulation) will likely be in promoting access to pipeline services and to weigh this against the likely costs of each form of regulation to service providers, users and end users. We will compare how effective and costly each form of regulation is likely to be to reach a conclusion about which form of regulation should apply to the pipeline and whether we should make the determination. In making the comparison, we will consider the key differences between full and light regulation, and the likely impact that these will have on promoting access and costs. This is a qualitative, and not a quantitative assessment. We will not attempt to quantify the full value of the benefits and costs under each form of regulation. However, we will consider quantitative data where relevant.*

20 NGL, section 112(2).
21 NGL, section 112(3).
22 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, p.23.

In terms of the specific meaning of the principal criteria, the AER has stated that it will interpret:[23]

- the promotion of access to pipeline services as spanning the ability of users to negotiate access to pipeline services, as well as the price and terms on which those services are provided, and
- the costs incurred by service providers and users, and the likely costs of end users, to refer to the administrative (regulatory) costs that may be incurred by service providers, users and end-users.

In terms of the secondary criteria, the AER has said that it will interpret the form of regulation factors as essentially guiding it in assessing the degree of market power that is possessed by a service provider in relation to a particular pipeline. We address some of the AER's specific statements about these factors in our discussion below.

2.2 Comment on the AER's interpretation of the principal criteria

We agree with the AER's description of its intended overall task, which is to determine the effectiveness of each form of regulation, and to weigh this against the costs associated with each form of regulation. We see this as implying a conventional assessment of the economic costs and benefits of choosing one form of regulation over the other.

However, we think the AER's statement that the requirement to consider the costs to the various parties relates only to administrative (regulatory) cost is unnecessarily limited, inconsistent with the National Gas Objective and inconsistent with the broader context of economic regulation. In our view, the reference to costs in these clauses should be taken as a reference to economic costs and include the full suite of costs that may be imposed upon (or saved by) service providers, users and end-users as a consequence of changing the form of regulation.

We note that there is a substantial economic literature that identifies the costs that may be caused by regulation, and especially by heavy-handed forms of regulation like ex ante price control. A summary of the relevant economic literature is provided in Appendix A. The costs that may be caused by regulation include:

- the potential for regulation to cause incentives for inefficient decisions on service quality, either to degrade the level of service / quality or to provide a level of service / quality that is excessive
- the potential to alter price structures away from those that are economically efficient and equitable, and
- the potential to either encourage excessive expenditure or insufficient expenditure.

The existence of such costs – and the potential for these costs to be material – is widely accepted as a fact, and therefore as a reason to show extreme caution before regulation is imposed or increased.

In the current matter, the principal economic cost that may be caused by applying scheme regulation to the SWQP is the potential to deter investment in projects that may be necessary to provide the services that users and/or end users seek and value. If necessary investments are deterred, then clear costs will flow through to users and/or end users, for example, by causing an increase in the price of

23 AER, Pipeline regulatory determination and elections guide, pp.24-25.

final gas prices (as basis-on-basin competition in gas production is inhibited and use of gas from more costly sources occurs), a switch to alternative and more expensive energy sources, and impacts on the electricity system if the gas pipeline network is not adapted to greater peak demands. We explain in Chapters 4 and 5 that the nature of the investment requirements for the SWQP, combined with the uncertainty of demand and exacerbated by the very prescriptive requirements of the pricing regime for scheme pipelines set out in the NGR, create a real potential that applying scheme regulation will deter efficient investment.

We observe that the AER does refer to the potential for such wider costs to be caused by increasing the degree of regulation and suggests that it may be considered. For example, the AER notes that the national gas objective would require a consideration of "the efficient investment in, and operation of, gas services for the long-term interests of consumers of natural gas".[24] However, these considerations should not be side issues that may be considered at the AER's discretion, but rather are a central component of the assessment of the economic costs to service providers, users and end-users.

2.3 Comment on the AER's view of the form of regulation factors

The form of regulation factors under section 16 of the NGL are:

a. the presence and extent of any barriers to entry in a market for pipeline services

b. the presence and extent of any network externalities (that is, interdependencies) between a natural gas service provided by a service provider and any other natural gas service provided by the service provider

c. the presence and extent of any network externalities (that is, interdependencies) between a natural gas service provided by a service provider and any other service provided by the service provider in any other market

d. the extent to which any market power possessed by a service provider is, or is likely to be, mitigated by any countervailing market power possessed by a user or prospective user

e. the presence and extent of any substitute, and the elasticity of demand, in a market for a pipeline service in which a service provider provides that service

f. the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be).

In our view the AER should give more consideration to the *economic* costs and benefits of scheme pipeline regulation than it suggests in its previous statements on form of regulation reviews. The following matters should be addressed.

- "Institutional delay" in reference tariff regulation that erodes the capability (nimbleness) of APA to make timely investments necessary to meet changing demand for pipeline services.

24 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, p.23.

- The absence of mechanisms in the NGR to properly deal with stranding risk in setting reference tariffs for scheme pipelines.

We focus on these issues in Chapters 4 and 5.

We also observe that, in relation to its consideration of the form of regulation factors that focus on "network externalities (that is, interdependencies)", the AER proposes to apply a non-standard, broader meaning of the term, with the AER commenting as follows:[25]

> *'Network externalities' as discussed here does not relate to the economic meaning of the term (i.e. referring to how the benefit an agent derives from a good changes as the number of other agents consuming the same kind of good changes). In this context, 'network externalities' refers to the way in which a service provider's market power is affected by other services it provides.*

Rather than focussing on network externalities as the term is understood by economists, the AER proposes instead to consider whether the pipeline operator (APA) may have vertical relationships that may either enhance its market power, or its incentive to misuse that market power.

While it is relevant for the AER to consider the effect of any vertical relationships on the presence and incentive to misuse market power, the more technical issue of whether network externalities (or interdependencies) exist and may affect market power also remains an important issue to consider.

To this end, we note that the Expert Panel – whose report recommended the form of regulation factors in the National Gas Law – drew a contrast between the interdependencies between point-to-point gas transmission pipeline assets and between electricity transmission assets. The Expert Panel noted that the former can be operated independently without any material loss of efficiency, whereas substantial efficiencies arise from operating electricity transmission networks jointly. The conclusion the Panel reached was that, relative to electricity transmission, competition between point-to-point gas transmission pipelines was substantially more feasible:[26]

> *As noted in the introduction, while the bulk energy transportation function performed by energy transmission and distribution networks is similar between electricity and gas, there are also important differences between gas and electricity networks which have implications for the extent of market power involved and the form of regulation that is appropriate.*
>
> *Electricity network services, for example, exhibit strong interdependencies (often referred to as network economies and externalities) which:*
>
> - *generate operational and economic efficiencies through the operation of the meshed network as an integrated system; and*
> - *make it difficult to identify which users of the system are causing costs or benefits for network operations and on other network users.*

---

[25] Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, p.26.

[26] Expert Panel on Energy Access Pricing, April 2006, Report to The Ministerial Council on Energy, pp.48-49.

> *This feature of electricity networks is a further barrier to entry and the promotion of contestability in service provision because of the difficulty in establishing property rights to the capacity of the network or to incremental augmentations of network capacity provided, which is a prerequisite for direct competition in the provision of network services.*
>
> *Network interdependence and externalities are less pronounced for gas transmission pipelines which more typically provide end-to-end services that can be operated independently without loss of efficiency. Thus, establishing means of contestability through tradable rights to pipeline capacity and pipeline-on-pipeline competition is more feasible in the gas transmission pipeline sector.*
>
> *The extent to which the differing extent of network interdependence as between electricity and gas networks impacts on the market power of the service providers is a further consideration in deciding the form of regulation for a particular service. Where strong network externalities and any-to-any supply characteristics strengthen the market power of service providers, price or revenue cap regulation is likely to be warranted. End-to-end networks with fewer network interdependencies and greater contestability potential are likely to be more amenable to less direct forms of regulation, particularly where there are alternative supply options and users have considerable countervailing market power.*

Indeed, we note that submitters to the Panel supported this distinction between the feasibility for competition in gas transmission compared to electricity transmission:[27]

> *The AER noted that some gas pipelines can operate independently, so the externality problems associated with the operation of networks may not arise. Further, some gas transmission pipelines may potentially be subject to more indirect competition than meshed networks.*
>
> *The TNOs [electricity transmission network owners] state that the meshed nature of electricity transmission makes it difficult to define and separate out a list of services that can or should be separated from the main revenue control and be subject to an alternative regulatory arrangement.*

Lastly, we note that the discussion above related to bulk supply, and so distinguishes between gas and electricity transmission. However, a consideration of interdependencies along the lines set out above also suggests that direct competition between gas transmission networks is much more feasible than direct competition between gas distribution networks.

27 Expert Panel on Energy Access Pricing, April 2006, Report to The Ministerial Council on Energy, pp.48-49.

3. Assessing whether monopoly rents have been made, and how prices may change with a different form of regulation, should have due regard to complexity

3.1 Introduction and conclusions

The AER has signalled that when forming a view on the likely effect of a change to scheme pipeline regulation:

- it will consider whether there has been an exercise of market power historically, including whether monopoly rents have been earned, referencing the ACCC's comments in this regard,[28] and

- a central consideration in deciding whether to make a scheme pipeline determination is to compare the prices for pipeline services that would be expected under scheme regulation to the prices that would otherwise prevail.[29]

We consider that both exercises will be very difficult, and unlikely to yield reliable information.

The AER's statements about historical excess returns reference the ACCC's comments in its east coast gas inquiry, which are based on the proposition that a monopoly rent would accrue where historical capital costs are over-recovered. There are two shortcomings with this.

- First, the ACCC's method requires the recovery of historical capital costs to be carefully measured, including that the historical allowable rate of return be consistent with how a firm would price in a competitive market, and further that an appropriate allowance is made for stranded asset risk. Neither of these were features of the ACCC analysis. Other possible assumptions about the historical recovery of capital costs (e.g., using accounting depreciation) also have fatal flaws.

- Secondly, defining excess returns in terms of historically recovered capital costs is inconsistent with how competitive markets work. A better definition is to compare an incumbent's prices against those that would allow a hypothetical (efficient) new entrant to recover its costs, again incorporating a rate of return that is appropriate for a competitive pipeline market. However, even this definition of excess return faces substantial practical challenges.

It will be a complex exercise to form a view on how scheme pipeline regulation would affect prices, as this effectively require a view to be taken on the key decisions the AER will be required to make if scheme pipeline regulation is imposed, but before the necessary analysis and consultation has been undertaken. Doing this task for a pipeline for the first time requires complex and contentious issues to be addressed – most notably, setting an initial capital base – and so the outcome that may be reached is far from obvious.

---

28 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, pp.13-14.

29 Australian Energy Regulator, September 2023, Pipeline Regulatory Determinations and Elections Guide Final Guide, p.24.

3.2 Inferring whether market power has been exercised from historical returns

3.2.1 Introduction

The AER has foreshadowed that an assessment of whether the SWQP has market power, together with the capacity and incentive to exercise that market power, will be a key input into its assessment as to whether a change to the form of regulation should occur. In turn, whilst much of the material the AER has summarised suggests that its assessment of market power will be based on considerations of market structure (e.g., the presence of substitutes, prospects of new entry and countervailing market power of shippers) and conduct (e.g., a consideration of the conduct of parties during negotiations), the AER has signalled that part of its assessment will comprise an assessment of whether the historical returns to the pipeline may comprise monopoly returns. To this end, the AER cites statements the ACCC made during its gas market inquiry to the effect that gas transport prices were thought to contain monopoly rents:[30]

> *Trends in the prices of services on the SWQP may help us assess the extent to which APA may hold and be exercising market power in the supply of services on the SWQP and assess how full regulation could affect the terms and conditions of access.*
>
> *In its 2016 Gas Market Inquiry Report, the ACCC found evidence of monopoly pricing on many pipelines, including for services on the SWQP. Subsequently, and as recently as December 2023, the ACCC reported that it is likely that such monopoly pricing has continued with prices broadly increasing in line with inflation (for prices as of July 2023).*

It is important that the AER understands the conceptual and practicable difficulties with attempting to deduce whether market power has been exercised from a measurement of historical returns. The ACCC's conclusions were based on the proposition that a monopoly return would be earned if an investor achieved greater than NPV=0 on its historical investment costs over the asset's life. We first address the practical difficulties with this achieved NPV=0 test of historical returns. We address the shortcomings with this conceptual framework, most notably that the framework is not consistent with how prices are set in competitive markets. We then present the alternative framework for determining whether monopoly rents have been earned, namely whether prices are consistent with those that would be predicted in a competitive market.

3.2.2 Practical difficulties with applying the "achieved NPV>0" test

The unrecovered capital method

As noted above, the ACCC's principal reasoning for suspecting that monopoly rents were being earned by gas transmission pipelines was based on an analysis of pipeline expenditures and revenues over time. Under this method, revenue that is in excess of operating expenditures (including taxation) and a return on the unrecovered invested capital is treated as a return of capital (depreciation) and deducted from the unrecovered value of invested capital. This calculation can be carried forward over time, so that an unrecovered value of invested capital is calculated at any point in time. Pricing that generates revenue that is incompatible with the unrecovered capital value would be deemed to be making monopoly returns.

30 AER, SQWP discussion paper, p.13.

When applying this method, the expenditures on the pipeline activities, and revenue received, are measurable, provided that historical records exist. However, shortcomings with the method are:

- any form of out-performance is treated as a recovery of capital rather than as an additional return (and vice versa for under-performance), whereas the out-performance may have reflected efficiency gains or an uncertain factor (e.g., demand) turning out to be better than forecast (the potential for which offset the possibility that the uncertain factor could have turned out to be worse than forecast), and

- an assumption is required about the required rate of return, included within which is an assumption about the premium that investors would require for bearing asymmetric risk (i.e., the risk of asset stranding) so that NPV=0 is maintained under the unrecovered capital method.

Expanding on the second point, the ACCC work and that of the AER under the former Part 23 regime assumed that the regulatory WACC was applicable to unregulated pipelines, and implicitly therefore that no premium is due for stranded asset risk. Both assumptions are likely to be materially incorrect.

In terms of the required rate of return, firms operating in competitive markets will factor in the assumptions that are relevant to those markets, rather than for a market that is protected from competition and regulated. There are two principal matters for which firms in a competitive market for pipeline services would be expected to adopt different assumptions to those of the AER in relation to regulated assets.

First, the indicator of relative risk – the asset beta – would be applied with a value that is relevant for pipelines that operate in a competitive market. There are a range of factors that would suggest that pipelines that operate in a competitive market would have a higher systematic risk than that a regulated monopoly energy network, including that there is an increased capacity for cash flows (revenue) to vary over the course of economic cycles. This is a matter that should be guided by empirical evidence.

Secondly, consistent with economic principles, the prices that are observed in competitive markets do not vary instantaneously with changes in interest rates, but rather tend to change slowly even in the face of an apparently permanent change in interest rates. This is because changes in interest rates have little effect on a firm's marginal cost (which is the dominant driver of short-term pricing/output decisions), but rather affect the long run equilibrium conditions for the market (i.e., as this changes the cost structure of the hypothetical efficient new entrant). Hence, changes in interest rates will only change the point towards which the process of entry and exist is expected to drive the market over the long-term. An implication of this is that the risk-free element of the rate of return that is assumed when estimating the cost of capital for a firm in a competitive market should reflect a longer-term view of interest rates, rather than following "spot" interest rates over time. This issue is highly relevant for the current matter because, during the period between the "global financial crisis" and the start of 2023, official interest rates were at historically low to extremely low levels.

As a logical matter, if the goal is to test whether a market is competitive, then it makes sense to apply assumptions that are consistent with those seen in a competitive market, including the cost of capital. In contrast, if assumptions consistent with a monopoly regulated firm deliver a finding of monopoly rents, but these conclusions are reversed if competitive market assumptions are applied instead, then the test must be inconclusive (i.e., whether monopoly rents are detected will depend on whether the inputs – including the cost of capital – assume a competitive market or a regulated monopoly market).[31]

In terms of other risks, in order that the recovered capital calculation delivers investors an outcome of expected NPV=0, it must be the case that either:

- there is perceived to be no risk as to whether the pipeline will remain in service until all costs are recovered, or
- an allowance to compensate for the early stranding of the assets is included as a cost in the recovered capital calculation.

In relation to the SWQP, stranding has been a material risk since the conception of the project,[32] although the precise magnitude of this risk as foreseen throughout the life of the pipeline is difficult to determine. However, we show in Chapter 5 that even reasonably modest levels of stranded asset risk would justify an asymmetric risk premium that is economically meaningful.

We observe that arriving at an estimate of the cost of capital that is consistent with the rate that would be factored into prices in a competitive market for gas pipelines, and deriving an appropriate allowance for stranded asset risk, are both complex tasks. However, the derivation of the unrecovered capital value of the SWQP – and hence whether monopoly returns are found – are likely to be very sensitive to these values.

Arbitrary assumptions are not a valid alternative to the recovered capital method

The alternative to applying the recovered capital method to calculate the extent of unrecovered investment is to assume a historical pattern of cost recovery. This is essentially what is being done when accounting values are applied: rather than calculating the historical return of capital, the assumption is simply made that capital is recovered evenly over time, and without any adjustment being made for inflation.

For infrastructure assets, however, accounting values are typically poor proxies for the extent of unrecovered capital that would result from a sensible tariff policy.[33] The reason for this is that, if straight line depreciation without inflation indexation were applied to set prices – which would be required for accounting values to provide a fair reflection of the unrecovered investment value – this would generate excessively high prices in the early years of an asset's life that would unnecessarily

[31] This process of assuming a particular case to be true (i.e., the market is competitive), and then testing whether this assumption can be rejected, is precisely how hypothesis testing is applied in classical statistical inference.

[32] Appendix A to our letter of instruction (appended to this report as Appendix B) summarises the history of the SWQP. Notably, demand for the pipeline in the early years never reached the installed capacity, and indeed the development of the coal seam gas fields around Roma/Wallumbilla – and the use of swaps by market participants – led to a further significant reduction in volumes on the pipeline. The SWQP has since benefited from the development of the export LNG industry (creating a demand for eastward gas flow, which included to address shortfalls in gas production from the coal seam gas fields in the early years) and from the substantial decline in gas reserves serving the southern states (creating a demand for westward flow); however, neither of these developments were likely to have been anticipated and assigned a material probability when the SWQP was developed.

[33] In this discussion, we are referring to accounting values in the absence of any revaluations (i.e., the original cost, depreciated).

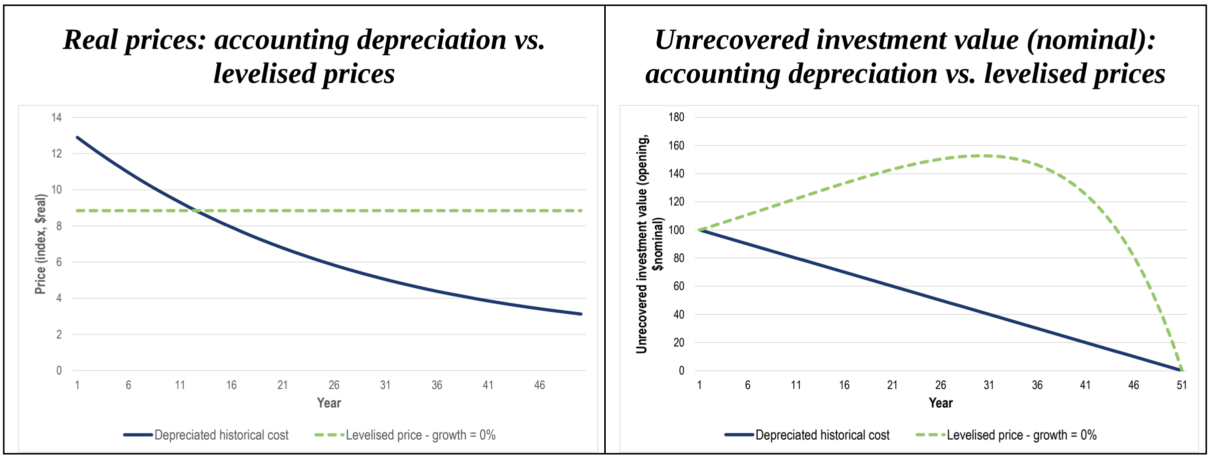
dissuade use of the asset. A more commercial time path of prices would be one that is smoother (i.e., more level) over time.[34] The result of this more commercial time path of prices is necessarily that the return of capital will be much lower than implied by accounting depreciation and so the unrecovered investment value is much higher. It is plausible that the true unrecovered investment value may be multiples of the accounting value.

This last observation can be illustrated with a simple example. It is assumed in this example that:

- there is a single-asset business with an original cost of 100, an expected life is 50 years and annual operating expenditure of approximately 2.5 per cent of the original cost (in real terms), and
- the real WACC is 6 per cent and inflation is forecast to be 2.5 per cent, and prices are determined to recover these values.

If demand was expected to be constant over the life of the asset, then the left panel of Figure 1 shows the time path of real prices (as an index) that would result if prices had been set to recover accounting depreciation in each year, compared to prices that were set to be constant in real terms (i.e., indexed to inflation). The right panel then shows the implied unrecovered investment value under each of the price paths over the life of the asset.

Figure 1 – Price and unrecovered investment cost (constant demand)



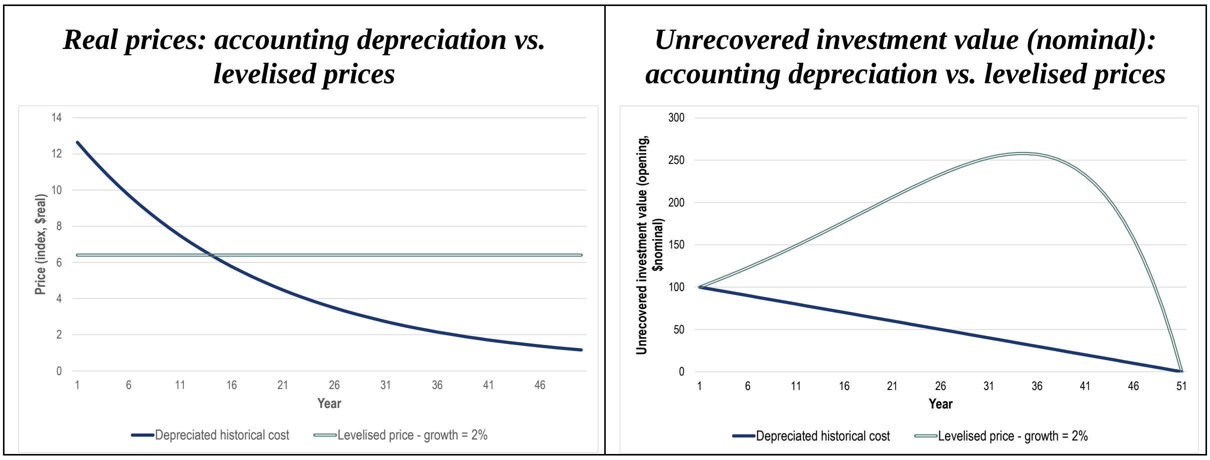
In this simple example:

- the recovery of accounting depreciation would cause prices to be substantially higher than the level real prices in the early years (almost 50 per cent higher in the first year), and then substantially lower in later years (38 per cent lower by year 30), and
- the unrecovered investment value with levelised prices is substantially greater than the accounting value – indeed, at the start of year 30 the unrecovered investment value is over 3.5 times the accounting value.

34 Indeed, the AER has denied several applications from regulated businesses to drop the indexation of the RAB on the grounds that the time path of prices is excessively front-ended, and so likely to be inefficient and adverse to the interests of customers.

The difference between prices that recover accounting depreciation and those that are fixed in real terms becomes even starker if demand growth is projected (and factored into pricing), and with those starker differences also manifest in the unrecovered investment value. The figure below repeats the calculation earlier, but assuming a growth rate in demand of 2 per cent.

Figure 2 – Price and unrecovered investment cost (2 per cent demand growth)



In this case, prices set to recover accounting depreciation would be almost twice the real levelised price in the first year, and 55 per cent lower in year 30, and the unrecovered investment value at the start of year 30 would be over 6 times the accounting value (and approximately 2.5 times the original cost of the asset).

These examples are simplifications of reality; however, the implications are clear that assumptions about the extent of past capital recovery – as would be implied from the use of accounting values – should be treated with substantial caution in any assessment of whether market outcomes are suggestive of the misuse of market power.

3.2.3 Conceptual difficulties with the "achieved NPV>0" test: this is not how competitive markets work

The more profound objection to the unrecovered capital method to detect whether monopoly rents are being earned is that this is inconsistent with how competitive markets work.[35] The test for monopoly rents that is inherent in the unrecovered capital method assumes that a firm would charge for a service and notch down its asset value as capital is recovered, and once the capital is recovered prices would be lowered to recover only its operating expenses (or, alternatively, the firm may never recover its cost, and may even close down prematurely). In contrast, however, in a competitive market:

- firms invest based upon their expectations about future costs, prices, demand, and other factors
- firms then make decisions to maximise profits on a forward-looking basis, which is kept in check by responses from existing competitors and the threat of entry of new competitors, and

35 Our use of the term "competitive markets" is used to refer to real-world competitive markets, for which the terms "effective competition" and "workable competition" are typically used.

- whether the firm is ultimately able to recover its cost – or indeed can recover more than this – depends on the dynamics of the market over time.

Long run equilibrium in a competitive market is said to be achieved when no net entry or exit is encouraged, meaning in turn that a new entrant can recover its costs (i.e., there is no net exit), but no more (i.e., there is no net entry). Importantly, however, the condition of long run equilibrium is the tendency of a competitive market, rather than as a point at which the market may remain once this is achieved.

The most reliable method to test for the existence of monopoly rents in a market is to assess whether the outcomes in that market are consistent with those that would be observed in a real-world competitive market that is in long-run equilibrium. This is equivalent to asking:

- whether the price that is being charged by the incumbent firm is consistent with the price that a hypothetical efficient new entrant would need to charge to break even, and equivalently

- whether, after valuing capital assets on a basis that is consistent with that of a hypothetical (efficient) new entrant, the incumbent firm is earning returns above the cost of capital.

The method of valuing capital assets implied by the second point above is the conceptual underpinning of the "depreciated optimised replacement cost" – or DORC – asset valuation method, provided that the method is applied correctly. The core concept of the valuation method is that the starting point for the incumbent's assets is the cost that would be incurred by a hypothetical (efficient) new entrant, but adjusted to account for differences in the forward-looking costs and service potential of the incumbent's assets compared to the hypothetical efficient new entrant's new assets.[36] In addition, as discussed above, the incumbent's returns should be tested against the rate of return that would be applicable to a firm in a competitive market, in order to allow valid inferences to be drawn (and avoid a self-fulfilling prophecy).

However, as explained earlier, the conditions of long run equilibrium are only the tendency of real-world competitive markets, and temporary divergences from this outcome should be expected. Moreover, permanent divergences from the conditions of long run equilibrium would be expected for firms that have superior efficiency to their rivals. Indeed, these factors, along with the measurement errors that are inherent in measuring returns and establishing the appropriate target in a conceptually correct manner, have led some competition authorities and commentators to question whether any reliable information may be drawn from measured profitability. For example:[37]

> *The economic and legal literature, while generally supportive of the logic behind the use of profitability estimates, has in general been rather sceptical about the use of profitability data as evidence of substantial market power. Judge Posner, for example, declared:*
>
> > *It is always treacherous to try to infer monopoly power from a high rate of return. … Not only do measured rates of return reflect accounting conventions more than they do real profits (or losses), but there is not even a good economic theory that*

36 A key difference will be that the incumbent's assets are likely to require replacement at an earlier date than "new" assets, and so the time-value effect of this earlier replacement is applied when valuing the incumbent's assets.

37 OECD Competition Committee, *Evidentiary issues in proving dominance*, Competition policy roundtables, 2006, p 40.

> *associates monopoly power with a high rate of return. [Blue Cross & Blue Shield United of Wisconsin v. Marshfield Clinic, 65 F.3d 1406 (7th Cir. 1995)].*

Similarly, Bork and Sidak have commented as follows:[38]

> *Neither economic theory nor empirical evidence indicates a dispositive relationship between profit margins and the possession of market power.*

Presumably in light of these factors, profitability assessments are not commonly applied in competition policy around the world, with the UK being a notable exception.[39]

Where profitability assessments are applied as a tool for testing the degree of competition, a common theme is that three elements are required before any inference can be drawn from measured profitability. These elements are that:

- the difference between measured profitability and "normal" profitability should be "unequivocally substantial"[40] or "significant"[41]
- the profitability gap referred to above must be persistent and, more specifically, endure over a sufficient period to account for fluctuations in the business cycle and investment outcomes,[42] and
- for there to be confidence that the observed returns cannot be explained by superior performance.[43]

3.3 Making a forward-looking comparison of prices under different forms of regulation

The AER's regulatory determination guide and discussion paper in relation to the SWQP scheme pipeline review suggest that a consideration of how a change to the form of regulation may affect transportation charges will be a central aspect of its analysis. The AER explains that the first part of the regulatory determination test requires a consideration of how a change to the form of regulation will affect the promotion of access, and the AER indicates that price is one of (and, in our view, likely

38 Bork, R H and Sidak, J G, *The misuse of profit margins to infer market power*, Journal of Competition Law and Economics, 9(3), 2013, p 512.

39 OXERA, *Assessing profitability in competition policy analysis*, A report prepared for the Office of Fair Trading by Oxera, July 2003, p 27.

40 Competition Commission, *Guidelines for market investigations: Their role, procedures, assessment and remedies*, April 2013, para 122, where the Commission notes that "[i]n cases where a persistent gap is not unequivocally substantial, it is particularly important for the CC to consider the analysis in conjunction with other information about the operation and nature of the market concerned".

41 OFT, *Assessment of market power: Understanding competition law*, Competition law guideline, 2004, para 6.6. Oxera, in a discussion paper for the OFT, opined that profitability estimates must be robust and their divergence from a relevant benchmark must be statistically significant, although it noted that the question 'how excessive is excessive?' cannot be answered clearly (OXERA, *Assessing profitability in competition policy analysis*, A report prepared for the Office of Fair Trading by Oxera, July 2003, p 124).

42 Competition Commission, Guidelines for market investigations: Their role, procedures, assessment and remedies, April 2013, para 121.

43 See, for example, OECD Competition Committee, *Evidentiary issues in proving dominance*, Competition Policy Roundtables, 2006, p 41.

the most important) the dimensions of access it will consider. However, the AER clarifies that it does not propose to undertake a purely quantitative assessment of the costs and benefits of a change to the form of regulation, but rather that its assessment will comprise a mixture of quantitative and qualitative elements.

Whilst we recognise that there is a requirement on the AER to consider how a change to the form of regulation is likely to affect access, forming even a qualitative (i.e., directional) view on the possible movement in transport charges will be a difficult task. Moreover, we do not think it is possible even to make the directional assumption that prices are likely to fall under full regulation. Indeed, as we address later in this report there are sound reasons why the reverse may occur.

First, whilst we note that many aspects of how prices are determined for scheme pipelines are locked in, a key matter that must be determined at the first review is the initial capital base of the pipeline. We observe that when the equivalent of scheme pipeline regulation was first applied to gas pipelines in the late 1990s/early 2000s, the determination of the initial capital base was an issue that was incredibly complex and contentious, where there were cases of large changes in regulators' decisions between draft and final decisions, and where there were also several successful merit reviews of decisions.

At the heart of the complexity and contention of setting the initial capital base is that the only definitive guidance that economic principles provide are outer bounds for the value, and this is typically a large range. That range is:

- a lower bound valuation equal to the value that could be obtained by using the assets for a different activity (their "opportunity cost"), although this is typically very low for infrastructure assets because they cannot be repurposed for other activities (in economic terms they are "sunk" investments); and

- an upper bound of valuation that is just less than what would cause customers to bypass the facility, for example, by building their own facilities.

Between this range, a key principle that regulators typically emphasise is that the outcome is objectively reasonable between the parties. This principle has economic content because an objectively reasonable outcome for the initial RAB is likely to provide incentives for efficient future investment by both the regulated business and customers of the regulated service. In turn, there are a range of indicators that regulators have considered when forming a view as to whether an initial RAB is objectively reasonable. To the extent that the criteria from the original National Gas Code are applied to determine the initial capital base for the SWQP, this will involve consideration of a large range of factors, including:

- the "depreciated optimised replacement cost" (DORC), being the predicted outcome for asset values in a hypothetical competitive market

- what was referred to as the "depreciated actual cost" (DAC) value, which was defined as:

  > *the value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code*

- that the initial capital base should "normally should not fall outside the range of values determined" according to the previous two methods (DORC and DAC)

- other "well recognised asset valuation methodologies"

- the "basis on which Tariffs have been (or appear to have been) set in the past"

- the "impact on the economically efficient utilisation of gas resources"

- the "comparability with the cost structure of new Pipelines that may compete with the Pipeline in question", and

- the "price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase".

In the original determinations of initial capital bases for gas transmission pipelines, the DORC method (as discussed above) was applied in the majority of cases (at least in the eastern states), although there was more variation at the distribution level.[44] Importantly, however, the National Gas Code criteria require a weighing up of a range of factors that are specific to an asset, and the final result cannot be known until this work has been done.

Secondly, as we discuss in detail in Chapter 5, the pricing regime for reference tariffs is very prescriptive, and provides the regulator with only one tool – advancing depreciation – to manage stranded asset risk in a way that (approximately) preserves NPV=0. We say in that chapter that it may not be possible to preserve NPV=0 purely by advancing depreciation, and so efficient investment may be deterred. However, putting that conclusion aside, it will be incumbent upon the AER to advance depreciation to the extent possible to eliminate stranding risk to the extent possible, and so achieve NPV=0 – and so preserve the incentives for investment – to the extent possible. In contrast, where tariffs are commercially negotiated, a wider range of options exist to preserve NPV=0 in the presence of stranded asset risk where tariffs are commercially negotiated (such as agreeing upon compensation for stranded asset risk or allowing the asset owner to benefit where assets remain in service for longer than expected).

A plausible outcome of using depreciation to eliminate stranded asset risk rather than the alternative options is that prices will be higher that if the alternative options were applied (we explain why this follows in detail in Chapter 5). This means that it is also plausible that the regulated prices for transport may be higher than the prices that would be commercially negotiated under the non-scheme regulatory regime, at least in the early years. We observe that the AER has expressed the view that a time path of prices that is more front-ended will be adverse to the interests of customers, even where the total of the revenue over time is maintained in present value terms.[45]

44 At the distribution level, the most commonly applied decision rule was that the initial capital base was set at the lesser of (i) DORC or (ii) the value that would preserve current prices, the latter of which became known as the "line in the sand" valuation method.

45 AER (2024), Re: Draft rule changes submission – Accommodating financeability in the regulatory framework and sharing concessional finance benefits with consumers, submission to the AEMC, February, p.2.

4. The regulation of capital expenditure under scheme pipeline regulation may deter pipeline investment

4.1 Introduction and conclusions

The medium to long term demand forecast for the SWQP is for increases in throughput and demand for ancillary services in the near to medium term, with a substantial risk of declines in demand in the medium to longer term. The associated outlook for investment in expansion of the pipeline is for near term investments in capacity through addition of compression.

Investments in SWQP capacity through additions of compression are being, and will be, undertaken on an opportunistic basis to capture opportunities to increase provision of pipeline services while dealing with potential competition from other service providers developing pipelines and LNG terminals. These circumstances of pipeline investment mean that the capacity expansion process (investment decisions, construction, and commissioning) is occurring over a compressed time frame and without capacity investments being supported by long-term supply contracts.

The compressed timing of pipeline investments and uncertainty in demand for pipeline services would create difficulties for incorporation into the capital expenditure approvals process for a scheme pipeline. The process and timing of approvals of capital expenditure under scheme pipeline regulation limits flexibility and certainty for a pipeline service provider in making pipeline investments over compressed time periods and therefore erodes investment incentives.

4.2 The current circumstances of investment in the SWQP

Capacity expansions of the SWQP are created by the addition of compression to the existing pipeline. The most recent expansion in capacity – the Stage 2 SWQP and MSP Expansion – has a two-year time frame from investment approval in 2022 to commissioning in 2024. [redacted]

- [redacted]
- [redacted]
- [redacted]

46 [redacted]

4.3 The process and timing of approvals of capital expenditure is unsuitable for the circumstances of the SWQP

Under the NGR the AER has an approval role for addition of new capital expenditure to the capital base of scheme pipelines, The NGR require the AER to determine whether new capital expenditure meets the "new capital expenditure criteria".[47]

Forecast capital expenditure for an access arrangement period can be notionally added to the capital base and a return earned and recovery commenced during an access arrangement period. However, this requires the capital expenditure to be forecast and adequately justified under the capital tests two years in advance of the access arrangement period and, hence, up to seven years before the capital expenditure would occur. Capital expenditure is only actually added to the capital base at the subsequent price review when the AER applies the tests of the expenditure criteria.

This treatment of capital expenditure under the NGR for scheme pipelines has the following features relevant to capital investments made within very short time frames.

- There is no equivalent to the "contingent project" regime that applies to electricity networks under the National Electricity Rules that would allow uncertain capital expenditure to be added to the capital base when and if it occurs during a regulatory period.
- A service provider cannot undertake an un-forecast capital project and have the capital costs (return on capital and depreciation) carried-forward to the next period – there is no flexibility for this in the NGR.
- The AER has the power to provide advanced approval of a project and reduce uncertainty over whether the capital expenditure will be added to the capital base at the next access arrangement review,[48] but this does not address the recovery issue and has never been used by the AER.

These features of the regulatory treatment of pipeline investment for scheme pipelines are not aligned with the current and forward-looking timeframes of investment decisions and expenditures for the SWQP.

In addition to deficiencies of timing in the regulatory treatment of capital expenditures, the current circumstances of the gas market will increase complexity for the AER in applying the tests under the new capital expenditure criteria. We see three reasons for this.

First, with uncertainty of medium to long term demand it will become more difficult for the AER to be conclusively satisfied that investments in pipeline expansion are adequately justified – for the purposes of the regulatory tests – by demand forecasts. Where an investment in capacity expansion is put forward under the "overall economic value" or "incremental revenue tests under the new capital expenditure criteria,[49] the AER would typically requirement a high level of certainty in the demand forecast. If this certainty is not possible (as is the case with current investments in the SWQP), the AER may determine not to permit a capacity expansion to be factored into reference tariffs under the full regulation regime, despite a pipeline service provider being willing to undertake the investment

47 NGR, Rule 79.
48 NGR, Rule 80.
49 NGR, Rule 79(2)(a) and (b)

where it has the capacity to bear and manage the demand risk as a non-scheme pipeline. In any case, the AER may increasingly find itself in the complex role of a "central planner" of the gas pipeline network, making judgements on highly uncertain medium to long term forecasts of gas demand and supply and how the pipeline network should be best configured. That is, a similar role to that of AEMO in respect of the electricity transmission network of the NEM. This is not a role for which the AER is currently well equipped.

Secondly, the medium to long term uncertainty in demand for pipeline services means that capital expenditure proposals are likely to be accompanied with proposals for an accelerated recovery of that capital as a means of addressing stranded asset risk, with the potential for a significant increase in prices. This is because the only mechanism in the NGR to address stranded asset risk – and so achieve an NPV=0 outcome – is to advance depreciation sufficiently to remove this risk (we address this issue in detail in Chapters 5 and 6). Also, new investments made with uncertain demand may require some protection against application of the redundant asset provisions of the NGR, which the AER has previously been reluctant to do (in its review of the revisions to the access arrangement for the Victorian Transmission System, the AER rejected a proposed fixed principle that the redundant asset principles not be applied in the future to investment in the Winchelsea compressor station).[50]

Thirdly, assessments of capital expenditure proposals for scheme pipelines are likely to become more contested and potentially broader in application. For example, the "overall economic value" test may necessarily become extended to comparison of gas pipeline investments with alternative technologies, such as if stakeholders force the AER to consider whether energy storage battery providers are a lower-cost substitute to gas for peaking generation causing customers to switch immediately to electricity as a preferred option over additional gas supply. The change to the National Gas Objective to require the AER to consider the achievement of emissions reduction targets further adds to the likelihood that the assessments of capital expenditure will be broadened and contested. Again, the AER may well find itself in the de facto position of "system planner" for the gas transmission network having to take account of matters such as having sufficient transmission capacity to enable the retirement of coal-fired generation while also facing opposition to expansion of gas pipelines.

The broadening and greater contest of capital expenditure assessments increases will increase the complexity and time for assessments of capital expenditure by the AER. The timing of capital expenditure approvals will increasingly be not fit-for-purpose for unanticipated investments determined and made over short time frames during an access arrangement period.

50 AER, June 2022, Draft Decision APA Victorian Transmission System (VTS) Access Arrangement 2023 to 2027 (1 January 2023 to 31 December 2027) Attachment 5 Capital Expenditure, p16.

5. Challenges of applying cost-based regulation where demand is uncertain and there is significant asset-stranding risk

5.1 Introduction and conclusions

Government policies to reduce carbon emissions and advances in renewable energy technology have changed the long-term outlook for natural gas. Policy targets for substantially reduced carbon emissions and emerging technologies for non-carbon energy sources have introduced an outlook of substantial medium to long-term declines in demand for natural gas and therefore gas pipelines, albeit in the short term there may be an increase in demand for gas as the economy electrifies and use of coal in electricity generation declines. This change in long-term demand outlook and the long-term demand risk created for gas pipelines is recognised by the AER both for the gas market generally[51] and the SWQP specifically[52].

The challenges with applying cost-based regulation to pipelines with high investment requirements and uncertain future demand are well established both in academic economics literature (see Appendix A) and in past policy reviews of the Australian framework for gas pipeline regulation (reviews undertaken by the ACCC and Productivity Commission are addressed below). The regulatory problem that future demand risk creates is known as the truncation problem, referring to a situation where conventional ex ante price regulation exposes the regulated business to the downside demand risk, but limits the ability of the service provider to capture the benefits of upside demand risk. The consequence is a "truncation" of the distribution of expected future returns under regulated pricing and an expected net present value of regulated cash flows of less than zero, contrary to the "NPV=0" principle that is a core objective of price regulation. The truncation of returns and likelihood of under-recovery of capital erodes incentives for otherwise efficient investment.

The problems in applying the "reference tariff" regime to gas pipelines in a context of significant demand risk are perfectly foreseeable. The reference tariff regime was never designed to deal with significant demand uncertainty and the NGR do not allow for regulated prices to include compensation for stranding risk. The regulatory regime of ex ante price regulation that applies to scheme pipelines was designed in the 1990s under premises of indefinite use of pipelines and constant or increasing demand. This is evident in provisions of the original National Access Code for Natural Gas Pipeline Systems (which remain in the NGR), and in early regulatory decisions. Examples are as follows.

- The new capital expenditure criteria explicitly contemplate an increase in scale of pipelines and capture of scale economies as a justification for allowing capital expenditure to be added to the capital base.[53]

- The rules for depreciation schedules explicitly contemplate using depreciation to set reference tariffs that promote the growth in the market for pipeline services, including specific provision for

51 Australian Energy Regulator, November 2021, Information Paper: Regulating Gas Pipelines Under Uncertainty, pp vii, viii, 22.

52 AER, March 2024, Form of Regulation Review: South West Queensland Pipeline Discussion Paper, pp14-18.

53 NGR, Rule 79(2)(b).

deferral of depreciation,[54] but there is no explicit consideration given to setting depreciation schedules is circumstances of a declining market.

- Up until about 2021,[55] depreciation allowances in cost-of-service calculations for scheme pipelines have typically been calculated by straight light depreciation over assumed technical lives of the assets, including an assumed life of principal pipeline assets in the order of 70 years.

- There is no explicit provision for operating expenditure to include such items associated with declines in the gas market. There has never to our knowledge been an allowance provided in regulated revenues to recover the projected cost of decommissioning facilities at the ends of their lives (i.e., if the industry had been assumed to be finite, then these costs would need to be recovered from customers in advance of the end of life occurring).

While the NGR make some provision to deal with demand risk through setting prices for multi-year regulatory periods and through adjustment of depreciation schedules, these measures are incomplete and inadequate. Addressing stranding risk by adjustment of depreciation schedules will tend to result in unnecessarily high prices in the near term to the potential detriment of customers, whilst also potentially not being sufficient to enable efficient costs to be recovered, this failing to provide an incentive for efficient investment.

In addition, the provision under the NGR for redundant capital to be removed from the RAB if it turns out to be subsequently unused exacerbates asset stranding risk beyond the natural, market-based risk described above, which again cannot be compensated under the NGR, further diminishing incentives for investment.

These are limitations of the NGR rather than potential outcomes of regulatory discretion. Regardless of any "sympathy" that the AER might have for a pipeline service provider facing material demand uncertainty and stranding risk, the current NGR regime for ex ante price regulation is too rigid to allow this risk to be properly addressed.

This chapter examines the truncation problem in price regulation and describes how the ideal regulatory method to deal with demand uncertainty and stranding risk is for regulated prices to include compensation for this risk. The limited measures under the NGR to deal with stranding risk, as well as those that exacerbate the risk, are then described leading to the conclusion that the reference tariff regime under the current NGR and as applied to scheme pipelines is unsuitable for regulation of pipelines facing significant stranding risk.

[54] NGR, Rule 89(1)(a) and (2)

[55] In 2021, the Economic Regulation Authority approved a "capped" economic life for the Dampier to Bunbury Pipeline of 2063, whereas under previous access arrangement approvals pipeline assets were depreciated over a 70 year assumed life. (Economic Regulation Authority, 2021, Final Decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025, pp345-357.) This was the first regulatory decision to allow changes in parameters to deal with a projected decline in the gas industry.

5.2 NPV = 0 and the truncation problem

5.2.1 NPV = 0 is a cornerstone of cost-based regulation

The fundamental challenge for regulators when setting cost-based prices for utility services is to strike a balance such that:

- the price is as low as possible for customers, but
- sufficiently high to provide both incentive and capacity for continued provision of the service.

In relation to utility services, an essential component of providing the incentive and capacity for continued provision of the service is ensuring that an incentive exists for efficient investment.

The resolution to the balancing referred to above is to set prices such that a service provider has the expectation of recovering its economic costs, including a commercial return on capital. An alternative – but equivalent – expression of this objective in terms drawn from finance literature is that investors expect cash flows with a net present value of zero from the activity in question.

The expected NPV=0 principle is central to the setting of prices in the framework of ex ante price regulation framework applied to scheme pipelines under the NGR. The principle operationalises the revenue and pricing principle of section 24(2)(a) of the NGL that "[a] scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services".

The basic method for setting reference tariffs applied by the AER for scheme pipelines is to set reference tariffs so that expected revenues and costs over an access arrangement period meet the NPV=0 objective given a forecast of demand for pipeline services and:

- a capital base value at the beginning of the regulatory period
- a forecast of capital expenditures for the period
- depreciation allowances for the period based on a long-term depreciation schedule for depreciation of capital assets over their forecast economic lives
- forecast operating expenditure, and
- a discount rate equal to the forecast cost of capital.

Under this method, the service provider is intentionally exposed to certain risks for the (typically five year) access arrangement period:

- the risk of demand being greater than or less than forecast for the period
- the risk of capital expenses being greater than or less than forecast for the period
- the risk of operating expenses being greater than or less than forecast for the period, and

- the risk of the cost of capital being greater than or less than forecast for the period.

It is implicit in the reference tariff setting framework that the upside and downside risks during the regulatory period offset each other and, hence, expected NPV=0 for cash flows over the access arrangement period. It is also an implicit assumption in the reference tariff setting framework that there is no risk in the recovery of the closing capital base that exists at the end of each regulatory period. Under the standard tariff model, which includes five-yearly updates of costs band demand forecasts, prices are set so that a commercial return and no more will be expected in future periods (i.e., there is no opportunity for "upside"), and so achieving NPV = 0 requires that there is also no long-term downside risk.

This condition of no risk in recovery of the capital base that is left at the end of a regulatory period implies substantial confidence in the long-term demand for the pipeline services. This arguably applied for many gas pipelines at the time access regulation for pipelines was introduced in Australia in the late 1990s and until relatively recently (and most likely does apply at the current time for regulated electricity networks). Most of the pipelines subject to full regulation had economic lives set for very long periods (up to about 70 years) under a presumption of no long-term demand risk or asset stranding risk; that is, a presumption of indefinite use of natural gas and the economic lives of pipeline assets being equal to technical lives.

It is now generally accepted that there is substantial medium to long term demand risk for the gas market and gas pipelines. The current NGR do not adequately cater for this risk in the regulation of scheme pipelines.

5.2.2 Demand risk causes "regulatory truncation" and NPV = 0 not to hold

Government policies to reduce carbon emissions and advances in renewable energy technology have changed the long-term outlook for natural gas. Government policies setting targets for substantially reduced carbon emissions and emerging technologies for non-carbon energy sources have introduced an outlook of substantial medium to long-term declines in demand for natural gas and therefore gas pipelines, albeit in the short term there may be an increase in demand for gas as the economy electrifies and use of coal in electricity generation declines. This change in long-term demand outlook and the long-term demand risk created for gas pipelines is recognised by the AER.[56]

Where there is substantial long-term downside demand risk, the expectation of NPV=0 for pipeline investments is no longer likely to hold under the pre-existing settings. This because, as noted above, regulation ensures that only a normal return can be earned if demand continues as forecast into the medium to long term. The service provider is exposed to the risk that demand disappears to the point where it is unable to recover its (substantially sunk) costs. This results in the probability distribution of future revenues being "truncated" and a reduction in the expected average return below the expected return in the unregulated scenario. That is, an expected NPV<0 outcome. This "truncation risk" was recognised in 2004 by the Productivity Commission as a potential adverse outcome of the

[56] Australian Energy Regulator, November 2021, Information Paper: Regulating Gas Pipelines Under Uncertainty, pp vii, viii, 22

form of price regulation applied to gas pipelines, with possible consequences of less or distorted pipeline investment.[57]

In an unregulated, competitive industry with demand risk, business set prices so that perceived downside risk (demand and revenues turn out to be worse than expected) is balanced by perceived upside risk (demand and revenues turn out to be better than expected) and a business has an expectation of – on average – an adequate return of and on capital. That is, an expected net present value of revenues and costs equal to zero (expected NPV = 0). However, the realised outcome for the business may vary from a loss to an above-normal profit.

Under price regulation, the truncation risks arises if regulated prices are set so that expected NPV=0 for an asset but then prices are revised in light of realised outcomes so that any actual higher-than-expected returns are curtailed by price re-sets, but any actual lower-than-expected returns are not compensated. The Productivity Commission recognised that this may come about through regulation being imposed on a business that faces effective competition due to a mistaken or biased interpretation of high profit as evidence of market power.[58]

For an existing regulated firm facing long term demand risk, the truncation risk arises where prices are set based on an expected asset life according to the NPV=0 principle. If demand continues beyond that expected asset life, price regulation will prevent any additional earnings. However, if demand diminishes before the expected asset life there is no compensation paid. Hence the existence of demand causes the probabilistic distribution of expected returns to be truncated and NPV<0.

The Productivity Commission recognised the potential for regulatory truncation of expected returns to deter or distort investment in pipelines by abandonment of projects that would otherwise occur by an unregulated business, building capacity only where demand risk is transferred to customers by long-term contracting, making only incremental expansions that compromise long-term scale economies, or delaying investment until demand is more certain.[59] The Commission found that actual evidence of deterred or distorted investment was mixed and inconclusive, but concluded that such distortion in investment was likely.[60] Notably, however, the Commission did not give any attention to medium to long term stranding risk from overall decline of the gas market as a relevant risk in considering regulatory truncation, which was consistent with the general view at the time of an indefinite future for the gas industry. The market outlook described by the Commission was for substantial growth in gas use out to 2020 and there was no contemplation of a decline in the gas industry.

57 Productivity Commission, 2004, Review of the Gas Access Regime, pp100-107. The terms of reference for the inquiry were for the Commission to analyse the benefits, costs and effects of the regime, particularly on investment and competition, consider ways to improve the regime, and identify and investigate the appropriateness of including in the Gas Code minimum price and non-price requirements.

58 Productivity Commission, 2004, Review of the Gas Access Regime, pp103, 105.

59 Productivity Commission, 2004, Review of the Gas Access Regime, p107.

60 Productivity Commission, 2004, Review of the Gas Access Regime, p138.

5.2.3 Valuing truncation risk and restoring NPV=0

One potential mechanism through which an NPV = 0 outcome can be restored where the potential cash flows are skewed (e.g., risks are predominantly downside) is to include an asymmetric risk premium in prices such that the NPV = 0 outcome is achieved.[61]

We have developed an illustrative numerical example to demonstrate how stranding risk may be assessed and an economically efficient level of compensation determined – in this case determined as a "stranded asset margin" in the rate of return.[62]

The assumptions applied in this example are:

- a regulated asset with an initial value of 100 and an expected economic life of 20 years
- a cost of capital (absent any stranding risk margin) of 6 per cent in real, pre-tax terms (which is approximately consistent with recent regulatory decisions), and
- a real levelised price is determined over the economic life of 20 years, and there is no new capital expenditure (operating costs are also assumed to be zero for simplicity, although this does not affect the results).

In this illustrative example, we consider possible asset stranding scenarios of:

- a likelihood of stranding at some time over the 20-year asset life of 10, 20, 30, 40 or 50 per cent, and
- a proportion of asset value lost in a stranding event of between 10 and 100 per cent.

The risk of asset stranding reduces the expected NPV for the project below zero, with a greater loss occurring with higher probabilities of stranding and greater losses of asset value under a stranding event (Table 1). In this illustrative example, the scenario with the highest stranding risk (50 per cent likelihood of stranding sometime over the next 20 years, with 100 per cent loss of asset value in a

61 As a simple example, a firm may require $100 in revenue to recover its economic cost (i.e., achieve NPV = 0), but if there is only a 90 per cent chance that the revenue will be recoverable, and a 10 per cent chance that the demand may disappear (and no revenue be received). There is assumed to be no prospect of receiving more than $100. In this circumstance, including an asymmetric risk premium in prices equivalent to $11.11 would be sufficient to restore expected NPV = 0. In this case, expected NPV = 90% x 111.11 + 10% x 0 – 100 = 0. Equivalently, the value of the potential outperformance (90 per cent x 11.11) is equal to the value of potential underperformance (10 per cent x -100).

62 This calculation is a by-product of the stranded asset risk premium calculation that follows (Table 2), with the latter calculation similar to that used by the New Zealand Commerce Commission in determining a "stranding allowance" to be applied to the rate of return in a pricing Decision for the Chorus fibre telecommunications network (Commerce Commission New Zealand, 13 October 2020, Fibre input methodologies: Main final decisions – reasons paper, pp587, 796, 797). In that case, the Commerce Commission determined a stranding allowance of 10 bp to be added to the rate of return on consideration of a probability of up to 10 per cent of stranding up to 30 per cent of the regulatory asset base over a 10 year period (p.598). The stranding premium the Commerce Commission allowed in that case reflected its view that Chorus' exposure to stranding risk in relation to its core network as these assets are used by mobile operators and would be even more essential to mobile operators with the roll-out of 5G mobile (the Commission did not think stranding by satellite operators was plausible).

stranding event) would cause the expected NPV of the project to be 24 per cent lower than the cost of the project (in present value terms).

Table 1 – Project NPV for a range of probabilities and consequences of asset stranding over a 20 year asset life and initial investment value of 100 (NPV=0 with no asset stranding risk)

Proportion of business lost as a consequence of the stranding event	Likelihood of stranding some time over 20 years: 10%	20%	30%	40%	50%
10%	-0.44	-0.90	-1.38	-1.89	-2.44
20%	-0.88	-1.80	-2.76	-3.79	-4.89
30%	-1.32	-2.69	-4.14	-5.68	-7.33
40%	-1.76	-3.59	-5.52	-7.57	-9.77
50%	-2.20	-4.49	-6.90	-9.46	-12.21
60%	-2.63	-5.39	-8.28	-11.36	-14.66
70%	-3.07	-6.29	-9.67	-13.25	-17.10
80%	-3.51	-7.18	-11.05	-15.14	-19.54
90%	-3.95	-8.08	-12.43	-17.04	-21.99
100%	-4.39	-8.98	-13.81	-18.93	-24.43

Stranding risk can, in principle, be compensated for by an increment to the regulated revenue stream either as an additional cash flow item or an increment to the rate of return. Both amount to the same thing: an increment to revenue so that the expected net present value of cash flows is equal to zero in the presence of stranded asset risk. The required additional revenue is the increase required to achieve expected NPV=0 given a demand outlook and a probabilistic view of the likelihood of asset stranding at some point during the expected economic life of assets.

To this end, Table 2 sets out the stranded asset risk allowance that would be required to compensate for the stranded asset risk under each of the scenarios shown in Table 1. In this example, the stranded asset risk allowance has been calculated as the increment to the rate of return that would be required to generate an expected NPV=0 outcome, given the assumed risk and consequences of stranding. Table 2 shows that the stranded asset risk margin that would be required for the highest stranding risk scenario summarised above is 3.74 per cent (i.e., equivalent to adding 3.74 percentage points to the rate of return).

Table 2 – Increments to the rate of return (standing risk margin) necessary to compensate a service provider for an expected probability and consequence of asset stranding over a 20 year asset life

Proportion of business lost as a consequence of the stranding event	Likelihood of stranding some time between year 1 and year 20: 10%	20%	30%	40%	50%
10%	0.05%	0.11%	0.17%	0.24%	0.31%
20%	0.11%	0.22%	0.35%	0.48%	0.63%
30%	0.16%	0.34%	0.53%	0.73%	0.96%
40%	0.22%	0.46%	0.71%	0.99%	1.30%
50%	0.28%	0.57%	0.90%	1.26%	1.66%
60%	0.33%	0.69%	1.09%	1.54%	2.04%
70%	0.39%	0.81%	1.29%	1.82%	2.43%
80%	0.44%	0.94%	1.49%	2.12%	2.85%
90%	0.50%	1.06%	1.70%	2.42%	3.28%
100%	0.56%	1.19%	1.91%	2.74%	3.74%

The addition of a stranding risk allowance to revenue – either as an additional line of cash flows or an increment to the rate of return – could perfectly compensate the service provider for the perceived risk of stranding in principle, although the calculation is sensitive to the views that are taken of the likelihood of asset stranding, and the consequences of an asset stranding event.

The problem of stranding risk can be developed with greater complexity in the particular circumstances of a pipeline with a mix of assets that may have different exposures to stranding risk. For example, the actual pipeline assets of a pipeline asset may have relatively low stranding risk, but compression assets added to the pipeline to meet near term demand for pipeline services such as peaking capacity and storage may be much more exposed to decreases and demand and more exposed to standing risk. This would suggest, at least in principle, different treatments of asset classes to deal with stranding risk and maintain NPV=0 for specific assets and/or capital investments, and for the pipeline as a whole.

5.3 The "tools" available to the AER to address demand risk are inadequate

5.3.1 Available tools

The AER has recognised the impossibility of compensating pipeline service providers for stranded asset risk under the current reference tariff regime.[63]

Despite the economic merit of direct compensation for stranding risk in achieving the NPV=0 objective, this is not able to be implemented under the current reference tariff regime of the NGR:

[63] Australian Energy Regulator, November 2021, Information Paper: Regulating Gas Pipelines Under Uncertainty, pp32,33.

- the building block components of a regulated revenue requirement are defined under the NGR and do not include any provision for an additional allowance to compensate for stranded asset risk, and
- there is no provision to include compensation for stranded asset risk as a margin to the regulated rate of return and, moreover, the rate of return for gas pipelines is determined uniformly across all scheme pipelines for five-year periods without the ability to treat pipelines differently according to stranded asset risk or for the AER to have discretion with respect to individual pipelines.[64]

In this section we outline the following two regulatory tools that are available to the AER under the current NGR address long term demand risk in accordance with the objective of expected NPV=0:

- adjustment of depreciation schedules to bring forward capital recovery in accordance with revised expectations of economic life, and
- longer regulatory periods.

We conclude that both tools are inadequate to fully achieve the regulatory objective of expected NPV=0 in all cases where future demand is uncertain, and especially in the context of the SWQP.

5.3.2 Adjustments to forecast economic life and depreciation schedules

Adjustment of depreciation schedules is the only mechanism contained within the reference tariff regime that explicitly deals with changes in projected economic life: “the depreciation schedule should be designed … so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets”.[65]

There have been some recent regulatory decisions that allowed an adjustment of depreciation schedules as a means of reducing a service provider’s risk of under-recovery of capital given outlooks for a decline in the gas market because of climate change policy and competition with renewable energy.

- The Economic Regulation Authority of Western Australia approved an access arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) with a decrease in projected economic life, expressed as a “cap” on economic life of existing and new assets of 2059.[66]
- The AER approved access arrangements for the Victorian gas transmission network with a 30 year cap on remaining and standard asset lives of the pipeline assets class reflecting an expectation of a "limited role for gas" beyond 2050.[67]

64 National Gas Law, section 30E.

65 National Gas Rules, Rule 89(1)(c).

66 Economic Regulation Authority of Western Australia, 1 April 2021, Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025, pp.324-330.

67 Australian Energy Regulator, December 2022, Final Decision, APA Victorian Transmission System (VTS) Access Arrangement 2023 to 2027 (1 January 2023 to 31 December 2027), Attachment 4 Regulatory Depreciation.

- The AER approved access arrangement for the Victorian gas distribution networks allowing acceleration of depreciation subject to a constraint of a 1.5 percent annual increase in real gas distribution tariffs (but not a change in projected economic life), also reflecting an expectation of a "limited role for gas" beyond 2050.[68]

Adjustment of depreciation schedules is a reasonable tool to address the potential for asset stranding events, in certain circumstances, which may well apply to some of the cases that were referred to above, particularly distribution networks. Where the "stranding event" in reality is just a reasonably predictable change in the likely useful life of an asset and the time path of decline in demand – for example, as the number of gas customers reduces over time in response to a well-planned government carbon reduction initiative – then shortening the period over which costs are recovered to match the (reasonably predictable) market life or front-ending depreciation could substantially eliminate stranded asset risk. To be clear, advancing depreciation only changes the timing of cash flow, it does not provide additional value (i.e., compensation) – accordingly, advancing depreciation is only an effective tool for addressing stranding risk if it is implemented to a sufficient extent that it has the effect of eliminating the risk.

We note there is likely to be a practical distinction here between the stranding risk facing transmission lines and distribution systems.

Customers connected to gas distribution systems are likely to transition away from natural gas in a relatively predicable manner as they switch appliances at the time that existing appliances wear out, combined with relatively long-term government policies that limit new or replacement gas appliances and gas network connections. A relatively predicable obsolescence path for distribution networks is therefore likely to result. As such, ensuring capital recovery is more readily able to be dealt with as a matter of depreciation profile, as the AER has done with the Victorian distribution networks.

However, the transmission pipeline network is less likely to have a uniform and predicable decline. This is because the gas market is likely to peak in the near term and then decline over the medium to long term. It is unlikely that there will be a uniform decrease in use of the entire transmission network, but rather the future of individual pipelines and particular assets of pipelines will depend on many factors including gas supply sources, locational demands, gas market competition and network interdependencies. The outlook for individual pipelines and assets is therefore one of uncertainty and risk of asset stranding.

Therefore, the circumstances under which advancing depreciation may be effective and/or desirable for addressing (i.e., removing) stranded asset risk for transmission pipelines are limited. A critical requirement is that there is a sufficiently long period during which stranded asset risk is immaterial, and during which it is both feasible and reasonable to recover cost. Therefore, advancing depreciation:

- may not be a feasible tool to address stranding risk if there is not a sufficiently long period of "demand certainty" during which it is possible to recover costs, and

68 Australian Energy Regulator, June 2023, Final Decisions, Multinet Gas Networks, AusNet Gas Networks and Australian Gas Networks, Gas Distribution Access Arrangement 1 July 2023 to 30 June 2028, Attachment 4 in all three Final Decisions – Regulatory Depreciation.

- even if it is feasible to recover costs over the period of "demand certainty", this may cause a sufficiently large increase in prices in the short term to be unreasonable.

The limits to the use of adjustments to depreciation schedules to deal with stranding risk are addressed in more detail below.

Projected investment under-recovery can be reduced but generally not eliminated

An adjustment to a depreciation schedule may occur to reflect a shorter economic life, but adjustments to depreciation schedules cannot readily maintain an NPV=0 expectation where there is a probabilistic outlook of lower demand or asset stranding. For example, the depreciation schedule for a pipeline might be adjusted to reflect an earlier economic life ending in 2050 (consistent with a net zero by 2050 climate policy objective); however, there may still be a probability of substantial declines in demand and partial or complete asset stranding occurring prior to 2050. While the risk (and projected negative project NPV) might be reduced, investors are not compensated for residual stranding risk and the NPV=0 objective would not be achieved.

Meeting the expected NPV=0 principle would only be achieved if the economic life underlying depreciation schedules is shortened to the extent that there is no material risk of asset stranding. In the current context of a net zero by 2050 climate policy objective, it is possible that meeting NPV=0 objective could require shortening of asset lives to as short as 10 years.

Bringing forward depreciation creates a price burden for near-term pipeline customers

Managing a risk of asset stranding by bringing forward depreciation to the extent necessary to eliminate this risk has the effect of increasing prices for near-term customers compared with providing compensation for this risk.

We have used our hypothetical regulatory price model to look at the price outcomes of bringing forward depreciation to eliminate stranded asset risk compared with providing compensation for the risk.

We consider the hypothetical scenario of:

- A regulated asset with an initial value of 100 and possible economic life of 20 years

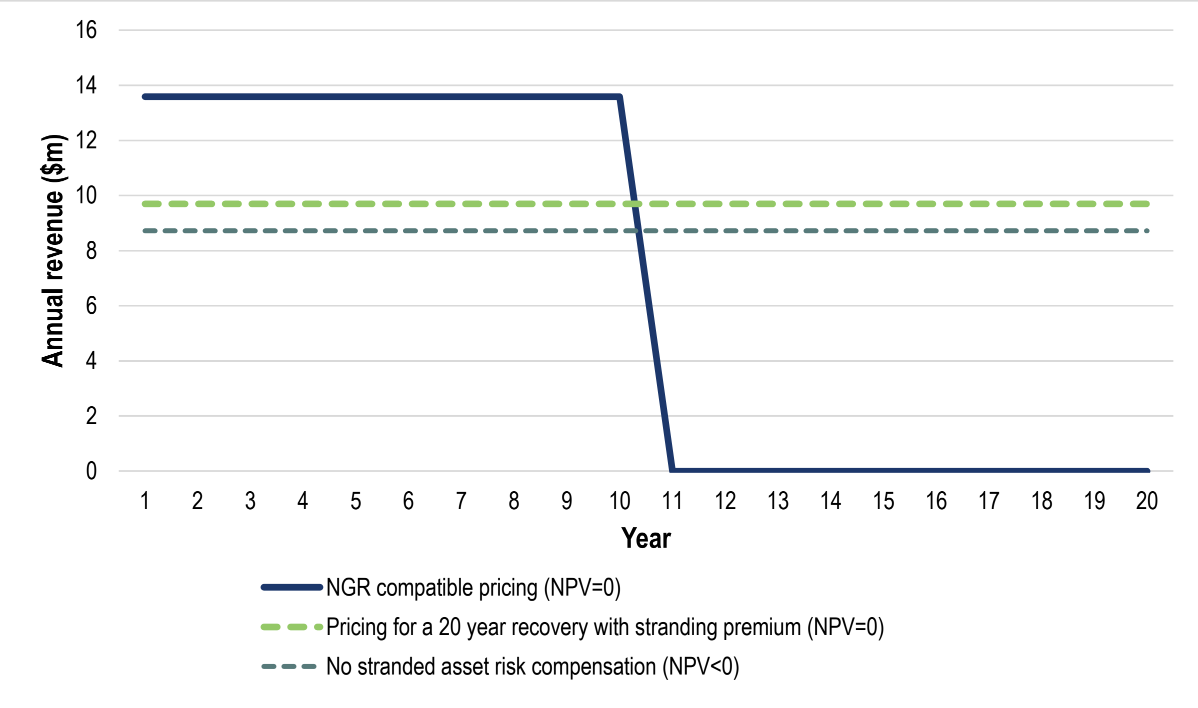
- A cost of capital (absent any stranding risk margin) of 6 per cent in real, pre-tax terms (again, approximately consistent with recent regulatory determinations), a real levelised price set over the possible economic life of 20 years, and zero new capital expenditure (and also zero operating costs for simplicity), and

- An immaterial stranding risk over the first 10 years, but then a 50 per cent risk of a complete stranding event in the following 10 years (implying an annual probability of such an event of 6.7 percent after year 10).

As noted above, we have calculated regulated outcomes as real levelised prices (Figure 3), with outcomes as follows.

- The levelised price over 20 years without regard to stranding risk is 8.7, but with an expected NPV = -10.0.
- Eliminating stranding risk by bringing forward depreciation ("NGR compatible pricing" with NPV=0) would require the asset to be fully depreciated by year 10. This results in a levelised price of 13.6 over years 1 to 10 and a price of zero for years 11 to 20 if the pipeline continues in operation.
- Providing compensation for stranding risk over the entire 20-year period (for NPV=0) results in a levelised price of 9.7.

Figure 3 – Levelised prices necessary to maintain a project NPV=0 using either early depreciation or compensation to address stranding risk in the final 10 years of a 20-year pipeline life



We make the general observations from this illustrative model.

- Eliminating stranding risk by advancing depreciation results in a large price increase over the 10 year period of depreciation (an increase of 56 per cent over the base price determined without regard to stranding risk).
- Eliminating stranding risk by providing compensation for the risk results in a relatively small increase in price (an increase of 11 per cent over the base price determined without regard to stranding risk).

In the circumstances described here, the latter price path – whereby stranding risk is accepted but compensated – would appear to generate an obviously preferable outcome to customers, as well as a likely preferable outcome for the service provider (this is because setting a lower price for years 1 to 10 may actually reduce the risk of the stranding event occurring). However, the preferable price path is not available if scheme pipeline regulation is applied, and so is a major cost to applying scheme pipeline regulation.

We return to this matter in Chapter 6, where we conclude that a major benefit of not applying scheme pipeline regulation is that the option exists for parties to negotiate the "preferable" price path. Also, the environment within which the price would be negotiated would bring to the table the expertise required to derive an appropriate asymmetric risk premium, provide the discipline for an efficient price to be agreed, and tend to favour a negotiated price outcome rather than a resort to arbitration to achieve a "regulatory counterfactual" price.

5.3.3 Longer regulatory periods

Longer regulatory periods can, in principle at least, reduce the potential truncation of returns under price regulation and therefore sustain incentives for investment in the face of stranding risk. However, longer regulatory periods are difficult to apply in practice and therefore are not a practical or credible approach to regulation in dealing with stranding risk.

Current regulatory convention is five-year regulatory periods that allow pipeline service providers to benefit from any demand upside during the period (relative to forecasts applied in setting prices), but also expose the service providers to downside, with a resultant incentive of services providers to grow the market for pipeline services. Absent any long-term demand risk, the periodic regulatory resets, including updated demand forecasts for new regulatory period are consistent with the NPV=0 principle over the life of the pipeline.

As explained above, the combination of limited-term regulatory periods and long-term demand risk can lead to asymmetric truncation of returns and NPV<0 for cash flows under regulated prices.

Using longer regulatory periods could reduce the asymmetric truncation by allowing service providers a greater ability to capture "blue sky" returns where demand and revenues are greater than originally forecast, offsetting longer term risks of lower demand. Indeed, if the regulatory period was set for the entire economic life of the asset using a probabilistic forecast of demand and stranding risk then, in principle, the same price path would be determined over the asset life as if compensation for stranding risk was determined and provided applying the same assumptions of stranding risk.

However, using long regulatory periods would create other problems in setting regulated prices. As capital and operating costs are not readily able to be forecast over the medium to longer term period, applying a long regulatory period would need to be undertaken with cost pass through arrangements or re-opening provisions for updating regulated prices in light of cost outcomes and updated forecasts. Also, mechanisms would have to be in place to allow proper recognition in prices of any additional costs associated with meeting un-forecast increases in demand, particularly capital expenditures. This may also require cost pass through arrangements or other mechanisms such as surcharges for incremental demand. Such arrangements are practically difficult to include in regulatory determinations, particularly determinations intended to apply for a decade or more.

There is some precedent for regulatory periods of longer than the conventional five years, but also precedent for some regulatory difficulty in approving longer regulatory periods with concomitant arrangements for cost pass throughs. The revenue determinations for the Murraylink and Directlink electricity transmission interconnectors both applied 10 year regulatory periods in the initial regulatory determinations.[69] Notably though, the regulatory period for both interconnectors was reduced to five years in the subsequent regulatory determinations, which in the case of Murraylink was at the initiative of the service provider due to dissatisfaction with the AER's draft decision positions on allowable cost pass throughs and efficiency incentive arrangements.[70]

5.4 There are some elements of the NGR that exacerbate the risk of under-recovery of capital investment

In addition to the deficiencies of the NGR in dealing with stranded asset risk, there are elements of the NGR that potentially exacerbate this risk:

- provision for the AER to determine assets to be redundant and remove the related asset value from the capital base, and
- the absence of flexibility in pricing of pipeline services within an access arrangement period.

These matters are addressed below.

5.4.1 Regulatory determination of asset redundancy

Capital redundancy provisions of the NGR increase the stranding risk for existing and new investment and conflicting with the NPV=0 principle for price regulation. This presents a material stranding risk for scheme pipelines.

The "capital redundancy" provisions of the NGR allow the AER to remove assets from the capital base of a pipeline (and so disallow any further return on or of capital) where the asset "cease[s] to contribute in any way to the delivery of pipeline services".[71]

The AER's power to disallow recovery of assets is constrained by a requirement to consider the uncertainty that a capital redundancy mechanism may create and the effect of the uncertainty on the service provider, users and prospective users, presumably including the stranding risk for the service provider.

The AER is also allowed to establish include a mechanism for sharing costs associated with a decline in demand for pipeline services between the service provider and users, presumably allowing for recovery of some, but not necessarily all, of the capital value through a means such as accelerated depreciation.

Scheme transmission pipelines that are regulated by the AER have access arrangements that include redundant capital mechanisms that would allow the AER to identify and remove redundant capital

69 Australian Competition and Consumer Commission, 1 October 2003, Decision Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue. Australian Energy Regulator, 3 March 2006, Directlink Joint Venturers' Application for Conversion and Revenue Cap Decision.

70 Energy Infrastructure Investments, January 2013, Murraylink Transmission Company Pty Ltd Murraylink Revenue Proposal Revisions, pp.6, 7.

71 NGR, Rule 85

(these mechanisms are largely a restatement of the relevant provisions of the NGR).[72] We are not aware of regulated gas transmission pipelines in Australia that have had the regulatory asset base reduced under a redundant capital mechanism.[73] However, despite a lack of precent of application, the capital redundancy provisions of the NGR remain a risk for unrecovered investment and new investment.

Indeed, the likelihood of the AER considering applying a capital redundancy mechanism in an access arrangement may increase when the gas pipeline industry starts to decline, and regulated prices consequently increase. While the hurdle of "cease to contribute in any way" may never be met for pipeline network assets, it could conceivably be met for compressor stations and like assets, which account for a considerable share of the cost of the SWQP. The absence of application of the capital redundancy provisions to date offers only limited comfort.[74]

- The AER has already indicated that it considers dealing with a decline in the gas pipeline market to be a matter of balancing interests (and sharing costs) between service providers and users rather than maintaining opportunities for recovering investment.

- Furthermore, the AER is not free to disregard the views of stakeholders that would be expected to lobby for any provision in the NGR that may limit price rises as the market for pipeline services declines.

- The AER has made a recent decision to refuse inclusion in an access arrangement of a fixed principle to protect a service provider from application of the capital redundancy provisions (Victorian Gas Transmission System and the Winchelsea compressor station[75]).

5.4.2 Limited pricing flexibility under the reference tariff regime

As already discussed above, the use of gas transmission pipelines, including the SWQP, is likely to change substantially. In the near term there may be an increase in demand for pipeline services, particularly for ancillary services such as storage and peaking services. In the medium to longer term there is likely to be a decline in demand for pipeline services as the gas market declines.

The changing nature of demand, increasing heterogeneity of demand across customers, and the medium to long term forecast of declining demand means that flexibility in pricing of services will become increasingly important to service providers in supporting new investment, maintaining demand for pipeline services, maximising the life of the pipeline, and managing stranding risk.

Flexibility in pricing, particularly variation in prices for a service according to the capacity to pay of the user, is not supported by the reference tariff regime which effectively requires a one service – one price requirement in setting prices. The only explicit provision for pricing flexibility is the provision

72 These are included in the access arrangements for the Roma to Brisbane Pipeline and the Victorian transmission system.

73 There has been one incident of redundant capital removal of which we are aware, which was for the Sydney gas distribution network, and had a unique set of facts.

74 The redundant capital provisions allow for redundant capital to be brought back into the capital base if the asset is subsequently re-used; however, this provision is only beneficial where the stranding event is temporary rather than permanent.

75 AER, June 2022, Draft Decision APA Victorian Transmission System (VTS) Access Arrangement 2023 to 2027 (1 January 2023 to 31 December 2027) Attachment 5 Capital Expenditure, p16.

for prudent discounts.[76] However prudent discounts are of limited practicality in negotiating pricing of services as:

- the discounts are subject to regulatory approval in advance for an access arrangement period, and
- as part of a regulatory approval process prudent discounts would be contentious between groups of customers.

The absence of pricing flexibility under the reference tariff regime for a scheme pipeline would remove an important tool for managing stranding risk of the SWQP.

76 NGR, Rule 96.

6. The negotiate-arbitrate regime for non-scheme pipelines is likely to deliver better outcomes for the SWQP than the reference tariff regime for scheme pipelines

6.1 Introduction and conclusions

In this chapter we compare the negotiate-arbitrate regime for non-scheme pipelines with the reference tariff regime for non-scheme pipelines in the context of the SWQP.

We first consider the regulatory approach best able to deal with maintaining incentives for investment in the presence of stranding risk. Attention is primarily given to the revenue and pricing principle of ensuring service providers have reasonable opportunity to recover costs of service provision and the consequent objective of expected NPV=0. This objective maintains incentives for pipeline investment and furthers the long-term interests of gas consumers. We note that past regulatory studies have favoured negotiate-arbitrate arrangements for pipeline regulation where demand is uncertain, for reason that negotiate-arbitrate arrangements avoid the risk of revenue truncation.

We compare the reference tariff and negotiate-arbitrate regimes, having regard to the limited tools available under the reference tariff regime to deal with stranding risk, but the greater flexibility of the negotiate-arbitrate regime. We observe that where there is material stranded asset risk, the negotiate-arbitrate regime for non-scheme pipelines is likely to deliver better outcomes than the reference tariff regime for scheme pipelines. There are two reasons for this.

- Compensating for stranded asset risk is not available to the AER under the NGR's reference tariff regime. The tools that are available to the AER are bringing forward depreciation or allowing longer regulatory periods, neither of which deals adequately with stranded asset risk while preserving the NPV=0 objective.

- Even if the NGR allowed for compensation for stranding risk, reaching a view on stranded asset risk and the correct level of compensation for a service provider would be a difficult exercise for a regulator, but relatively straight forward for-well informed counterparties determining prices and other contractual parameters in a negotiate-arbitrate regime.

Our conclusion follows that in situations of material stranding risk the negotiate-arbitrate arrangements applying to non-scheme pipelines are likely to deliver outcomes that better meet the National Gas Objective and subordinate objectives of the NGL and NGR than the reference tariff regime applying to scheme pipelines.

6.2 The negotiate-arbitrate regime is better able to deal with stranding risk

6.2.1 Relevant past regulatory studies have favoured negotiate-arbitrate arrangements where demand is uncertain

The Productivity Commission's 2004 inquiry into the National Gas Access Regime gave particular attention to risk in investment in regulated pipelines and potential erosion of incentives for efficient pipeline investment and in particular asymmetric truncation risk[77] and asset stranding risk.[78] The Commission considered that "the Gas Access Regime is likely to distort pipeline investment in favour of lower risk projects, including through the deferral of riskier projects. This is due to the combination of the current coverage test and the potential for regulatory error, regulatory risk and asymmetric truncation."[79]

The Commission considered that these risks cannot readily be addressed under the reference tariff regime and recommended that a light-handed form of regulation be introduced, comprising a negotiate-arbitrate regime, i.e., that included requirements for information disclosure, a process for negotiation and dispute resolution procedures that included provision for binding commercial arbitration.[80]

Importantly for the current discussion, the Commission also considered that decisions and recommendations on the form of regulation should err on the side of light-handed regulation. That is, the Commission considered that regulation with access arrangements should be applied only where the net benefits of access arrangements are markedly greater than the net benefits of light-handed regulation.[81] The concept of net benefits analysis of different forms of regulation is reflected in the criteria for a form of regulation review, albeit generally limited to producers, pipeline service providers, pipeline users and gas consumers rather than a broader assessment economy wide benefits.

After the Productivity Commission inquiry, light-handed regulation was introduced to gas pipeline regulation and exists currently under the NGR for non-scheme pipelines. There have been several reviews and changes to the arrangements for light-handed regulation since first introduced, particularly in strengthening information disclosure requirement.[82] The current regime for non-scheme pipelines was developed following the ACCC's 2019 Gas Inquiry in which the ACCC found that the light-handed arrangements as they existed at that time (the then Part 23 of the NGR) "appears to be working as intended and there are signs that it is having a positive effect on pipeline prices and the contracting environment". The ACCC recommendations dealt with a range of improvements to the framework, relating to information disclosure and ensuring a credible threat of arbitration.[83]

In our view, the case for form of regulation decisions to err towards light handed regulation has become stronger as transmission pipelines face increasing stranding risk. Reasons for this view are presented below.

77 Productivity Commission, 11 June 2004, Review of the Gas Access Regime, pp104-108.
78 Productivity Commission, 11 June 2004, Review of the Gas Access Regime, pp114-115.
79 Productivity Commission, 11 June 2004, Review of the Gas Access Regime, p138.
80 Productivity Commission, 11 June 2004, Review of the Gas Access Regime, p349.
81 Productivity Commission, 11 June 2004, Review of the Gas Access Regime, p228.
82 For example, the Expert Panel on Energy Access Pricing, April 2006 (Report to the Ministerial Council on Energy, p45) and the Vertigan Review in 2016 (Vertigan, M.,14 December 2016, Examination of the current test for the regulation of gas pipelines).
83 ACCC 2019, Gas Inquiry 2017-2020 Interim report, pp18,160.

6.2.2 Compensating for stranding risk is a difficult exercise for a regulator but is readily achievable in a negotiate-arbitrate framework

As discussed in Chapter 5, stranding risk would ideally be best addressed in pipeline regulation by allowing compensation for this risk in regulated revenues, either as a cost line item or increment to the rate of return in the building block method of calculated a revenue requirement and prices.

Calculating an amount of compensation for stranding is straight forward in principle, as shown in the illustrative example used in this report. However, it is potentially difficult in practice as it requires a quantification of stranding risk looking several years or decades into the future.

The consideration of stranding risk and an amount of compensation in the rate of return (or cash flows) is a different practical exercise to estimating systematic risk and the weighted average cost of capital. Determination of the WACC is theory and evidence based, using readily available data that is industry specific rather than firm specific. It involves statistically estimating a market view of investors of the expected risk of a particular class of investment or project and the amount of compensation for this risk that is required to attract investment. Estimates of the WACC, if not quite unique, are within a narrow range. Whilst disputes about the WACC in regulatory price setting are common, the disputes are over nuances of finance theory and small ranges in values of parameters. Disputes are driven by the value at stake with small changes in the WACC and not by wide variations in estimates of risk or required returns for a given level of risk.

This is not the case with a regulatory decision on stranding risk. Stranding risk is specific to a particular pipeline and estimating this risk would be an exercise in informed speculation about future changes in the gas market, rather than a statistical estimate. There is no unique estimate, or even a narrow range of estimates, of the risk than can be arrived at by a generally accepted method.

This difficulty was recognised by the Productivity Commission in its 2004 inquiry. The Commission considering that regulators could in theory address the distortionary impact of asymmetric truncation on investment but that significant implementation issues would have to be addressed. The Commission dismissed the idea of project-specific truncation premia as too difficult for regulators.[84]

While potentially difficult in a regulatory process, properly recognising stranding risk is likely to be readily achievable in a negotiation process between a pipeline service provider and a pipeline user.

The task in respect of standing risk is different in a negotiation. That is, the task is for the parties to the negotiation to agree on a view of the future that they can work with for the purposes of the negotiation, and that are motivated to reach an agreement. Moreover, the pipeline service provider and user are likely to be well informed and capable of a constructive discourse on stranding risk as both parties face the effectively the same risk to their gas business.

This is different to the regulatory decision-making process, which is to derive an evidence-based estimate of risk that needs to be resilient to challenge by both the service provider and users that assume adversarial positions in the regulatory process.

---

[84] Productivity Commission, 11 June 2004, Review of the Gas Access Regime, p408.

6.2.3 The price path and contract terms determined in a negotiation process are likely to be more efficient and more favourable to both the service provider and users than a regulatory decision

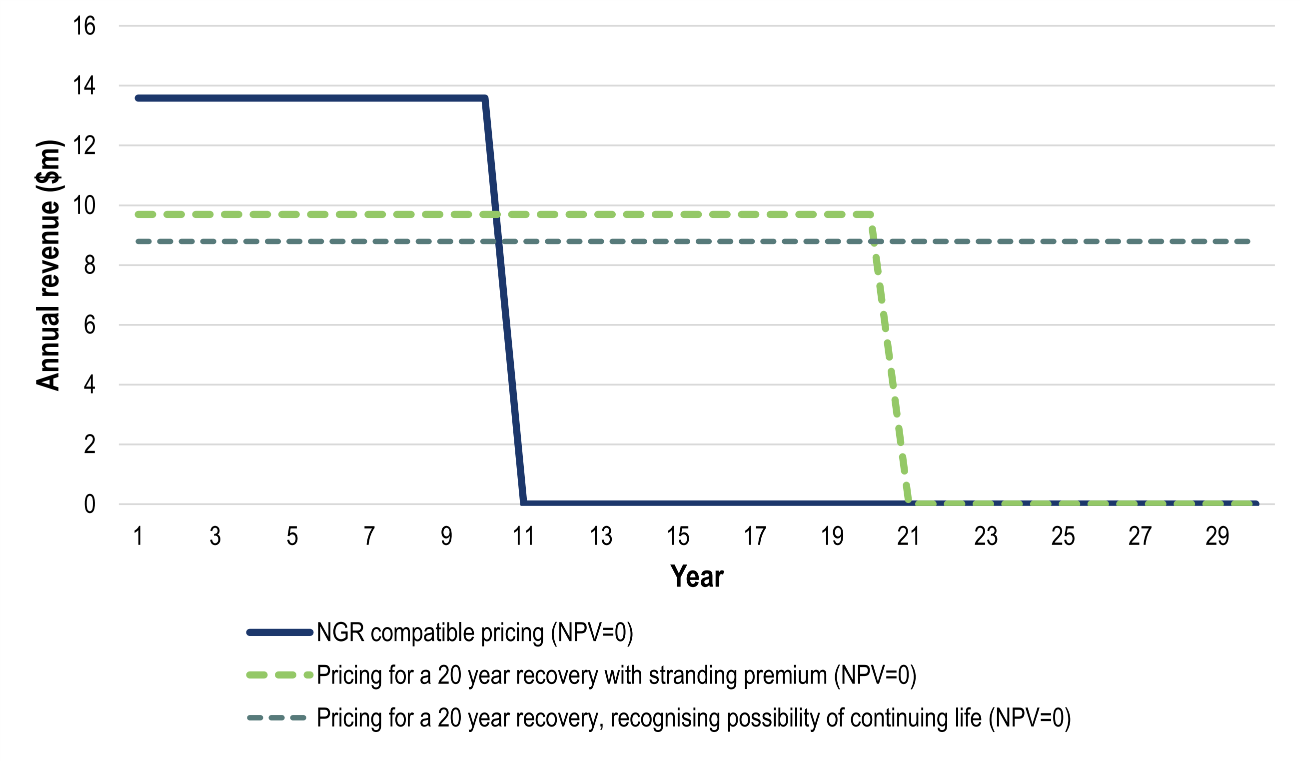
A negotiation process allows more flexibility than ex ante price regulation to determine price and non-price contract terms to address stranding risk and prices set under the scheme pipeline regulatory regime.

Pricing to include compensation for stranding risk provides for more flexibility in pricing than a regulated price where the only regulatory tool to address stranding risk is to accelerate depreciation to the extent necessary that stranding risk is eliminated. The greater flexibility in pricing allows the service provider to better manage demand and the market for pipeline services rather than being restricted to the price path of regulation that, as indicated in Chapter 5 and below, may result in a substantially higher near-term price path. An access negotiation process in the presence of medium to long term stranding risk would tend to result in lower prices in the near term and provide strong incentives to achieve a negotiated outcome.

As shown in the price profile of Figure 3 for the hypothetical pricing model (in Chapter 5), bringing forward depreciation to the extent necessary to eliminate stranded asset risk and maintain expected NPV=0 can result in a large increase in prices over the depreciation period. This front-ending of cost recovery has the potential to disadvantage customers and may also not be preferred by the service provider as the higher early-year prices may enhance the risk of stranding, or simply not be chargeable. Whilst service providers are free under the scheme pipeline regime to charge less than the reference tariff, the resultant shortfall in cost recovery would be borne by the service provider. In this sense, the imposition of scheme pipeline regulation in the presence of stranding risk may be fundamentally inconsistent with the service provider having the reasonable opportunity to recover the costs of service provision.

Moreover, there are further options available with negotiated prices. In the simple example presented in Chapter 5, the service provider may also have regard to the possibility that the pipeline life might extend beyond the 20 year expected economic life. This potential is shown in Figure 4 below. If the same annual probability of a stranding event were to continue, then there would be a 50 per cent chance of stranding by year 20 (as before) and a 75 per cent chance of a stranding event occurring by year 30. If the service provider was to have regard to this possibility of an ongoing life beyond 20 years (however remote), then the asymmetric risk premium it would require to preserve an expected NPV = 0 outcome – and hence the price – would be lower again. In this simple example, the levelised price falls to 8.8, compared to 9.7 where cash flows only to year 20 were considered (Figure 4).

Figure 4 – Levelised prices necessary to maintain a project NPV=0 using either early depreciation or compensation to address stranding asset risk in the final 10 years of a 20-year pipeline life



A negotiation process also allows other price and contract terms to be bought to bear in both the service provider and user managing near-term investment requirements and medium to longer term market decline and stranding risk.

Where stranding risk exists, a negotiation process is likely to address parameters of a service contract that allocates and prices the stranding risk. For example, a gas transportation contract will allocate stranding risk between the service provider and pipeline through parameters such as the term of the contract, levels of contracted capacity and ability to "swing" gas throughputs, price structures (particularly relativities of fixed and variable charges), and contract re-openers.

These contract parameters determine the stranding risk borne by the pipeline service provider and therefore the margins in service prices that would be negotiated to compensate the service provider for this risk.

Flexibility in these contract parameters will improve incentives and capacity for efficient pipeline investment.

6.3 The circumstances of the SWQP support the negotiate-arbitrate regime – countervailing market power and other characteristics of customers

There are two closely related factors that are relevant to the question of whether the AER should make a scheme pipeline determination for the SWQP.

First, the AER is required to consider whether there may be countervailing market power in the relevant market, as this is contained within the form of regulation factors. Countervailing market power refers to a situation where, in essence, buyer market power may be exercised and so create an offset to the ability for the seller to exercise market power. A finding that there is countervailing market power may then lead to a conclusion that the apparent market power of the seller is constrained by the structure of the buyer-side market of the market. The degree of concentration amongst the buyers of the services of the SWQP are relevant to an assessment of the degree of countervailing power, although this will also be influenced by a range of other factors.

Secondly, the characteristics of the buyers of the SWQP's services will also affect the extent to which the negotiate-arbitrate regulatory regime (with information disclosure) that applies to non-scheme pipelines is effective in addressing the market power that the SWQP may possess. Thus, a relevant consideration under the negotiate-arbitrate regime is whether pipeline users are sufficiently large, resourced and motivated to effectively use the negotiate-arbitrate regime to counter any market power of the SWQP owner.

Relevant circumstances of the SWQP for the AER to take into account when considering the related issues of whether the buyers of the SWQP's services are likely to exercise countervailing market power, as well as the effectiveness of the negotiate-arbitrate regime for controlling any market power of the SWQP, include the following.

- We are advised that there have been past periods during which negotiations for access on the SWQP have been characterised by substantial spare pipeline capacity and substantial negotiating power of users, and the access terms and prices from these periods continue to have precedent value in new negotiations.[85]

- While there are many users of the SWQP, pipeline use is dominated by the few large gas suppliers and retailers that would have the capacity and motivation to present a credible threat of taking an access dispute to arbitration.

- An arbitrated outcome for any large user would have precedent value in any access negotiation and arbitration for other users, which is likely to have the effect of spreading the benefits of arbitrations across the broader pool of shippers or potential shippers. The broad information provision requirements for non-scheme pipelines – including the requirement to publish information on actual prices charged – would facilitate this spreading of the outcome of an arbitration.

[85] Refer to Appendix A of our Letter of Instruction, appended to this report as Appendix B.

Appendices

A. Economic literature on the economic costs of regulation

The central theme of this report is that in undertaking a form of regulation review the AER should have regard to the *economic* costs and benefits of changing the SWQP from a non-scheme pipeline to a scheme pipeline. The principal concern regarding the SWQP should be to maintain incentives (or more particularly to avoid creating disincentives) for near-term investment in pipeline capacity, despite a medium-to-long-term outlook of gas market decline and associated risks of asset stranding. We have concluded that the reference tariff regime applying to scheme pipelines under the NGR is not able to adequately deal with the asset stranding risk facing transmission pipelines, and would likely result in inefficient pipeline pricing, and greatly diminished incentives for near-term pipeline investment. We further concluded that these outcomes would be adverse to gas consumers, and further would increase the cost of – and potentially delay – the medium to long term transition away from fossil fuels.

These potential outcomes of scheme pipeline regulation of the SWQP would be dynamic inefficiencies in the provision of pipeline services (i.e., efficiencies related to long-term investments) that would result from application of a heavy-handed form of price regulation.

There is a substantial economic literature dating back several decades dealing with dynamic inefficiencies of price regulation, with varying findings.

The seminal work of Averch and Johnson was an argument that rate of return regulation in the USA presented a risk of over-investment in regulated infrastructure where the regulated rate of return is greater than the cost of capital of the infrastructure business.[86] This was followed soon thereafter by the paper of Baumol and Klevorick that confirmed, at least in principle, the possibility of the "Averch Johnson effect" but demonstrated the possibility of widely diverging effects of regulation (including that an incentive may be created for over- *or* under-investment) depending on the assumptions made about regulatory arrangements and behaviour of the regulated firm.[87]

These seminal studies initiated a long sequence of research exploring the incentive effects of regulation, which were undertaken in the context of a recognition that regulation is inherently imperfect, so that investigating the economic benefits of regulation amounts to a comparison of imperfect markets against imperfect regulation.[88] The effects of regulation on investment are highly dependent on the specific characterisation of the regulatory regime and of the regulated asset in theoretical studies or, in empirical studies, the specification of regulatory regimes and circumstances of regulated markets and firms. Consistent with the topic of this current report, the question of whether regulation will distort investment (and, in particular, result in the deferral or absence of otherwise efficient investment) "is not whether there is a fundamental contradiction between

86 Averch, H., Johnson, L.L. (1962). Behavior of the firm under regulatory constraint. American Economic Review 52, 1052-1062.

87 Baumol, W.J., Klevorick, A.K. (1970). Input Choices and rate of return regulation: an overview of the discussion. Bell Journal of Economics and Management Science 1 (2), 169-190.

88 Joskow and Rose (1989). The Effects of Economic Regulation, in Handbook of Industrial Organization, Volume II, Edited by R. Schmalensee and R.D. Willig. Elsevier Science Publishers B.V.

investment and regulation, but whether in certain circumstances and under certain market constellations regulation has a negative impact on investment incentives and innovation”.[89]

Examining the effects of regulation on investment has therefore tended to comprise empirical studies in the context of the specific circumstances of industry sectors and regulatory arrangements. Focussing on studies that looked at effects of regulation on investment in circumstances where there is a pressing near-term investment requirement, it has most commonly been found that greater regulation retards investment and, correspondingly, that reducing regulation increases rates of investment even if this means forgoing the objective of constraining the exercise of market power. Some examples include:

- In Europe, third party access regulation of gas pipelines and related infrastructure was observed in European Commission studies to be constraining investment in the development of gas networks. This lead to the introduction of rules for regulatory exemptions to be granted for investments in major new infrastructure and for increases in capacity of existing infrastructure, which had the result of increasing rates of investment.[90]

- In the US gas transmission and electricity transmission sectors, where relatively rapid investment is required to adapt infrastructure to deal with changing electricity and gas markets, investment was observed to occur at a greater speed and scale in the gas transmission sector where pipeline companies had considerable scope to contract directly with pipeline users. This contrasted with the case of electricity transmission, where service providers have revenues determined by cost-of-service regulation.[91]

A related line of inquiry on the topic of whether regulation should be imposed is how the potential economic benefits of regulation compare to the potential economic cost of disincentivising investment. This problem includes a time dimension: whether the near-term economic benefits of regulation to the direct users of the infrastructure service and end consumers (in lower service prices) are likely to be greater or less than the economic costs of longer-term under investment.

Studies to estimate the economic costs of under-investment have taken different forms, which include whole-of-economy modelling of the effects of the presence/absence of investments to reduce infrastructure constraints, as well as estimates of value of lost load (VoLL) as a proxy for the costs

89 Heinacher, Peter; Preissl, Brigitte (2006). Fibre-optic Networks: On Investment, Regulation and Competition, CESifo DICE Report, ISSN 1613-6373, ifo Institut für Wirtschaftsforschung an der Universität München, München, Vol. 04, Iss. 3, pp. 22-28.

90 European Commission (2009). Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity. Online: https://energy.ec.europa.eu/system/files/2014-10/sec_2009-642_0.pdf. Official Journal of the European Union, Directive (EU) 2019/ 692 of the European Parliament and of the Council - of 17 April 2019 - amending Directive 2009/ 73/ EC concerning common rules for the internal market in natural gas.

91 Adamson, S., 2018. Comparing Interstate Regulation and Investment in US Gas and Electric Transmission. Journal Economics of Energy & Environmental Policy (EEEP), Vol. 7-1. https://www.jstor.org/stable/27030609

that might be incurred by service consumers if under investment erodes reliability of energy supplies. For example:

- Van Oostvoorn et al estimated the potential effect of investment deferral in European gas infrastructure to determine the economic impacts of investment deferrals (finding that investment deferrals would increase gas prices up by 25% over 10 years).[92]

- Praktiknjo et al reviewed average VoLL of electricity outages in European countries (indicating an average value of 9.39 €/kWh with a standard deviation of 14.72 €/kWh, with the large variations attributed to differences of estimation methods in each case.[93]

The significance of these and other such studies to any particular investigation of the economic benefits and costs of regulation is not to directly inform estimates, but rather to indicate:

- first, that the investigative approach taken is to look at economic costs, and

- secondly, that the economic costs can be very large, and likely to exceed by orders of magnitude the "out-of-pocket" costs associated with a change to the form of regulation.

92 Van Oostvoorn, F., Wietze, L and Hobbs, B.F. 2008. Natural Gas Corridors between the EU and its Main Suppliers: Simulation Results with the Dynamic GASTALE Model. Energy Policy. 36. 1890-1906.

93 Praktiknjo, A., Hähnel, A.P., & Erdmann, G., 2011. Assessing energy supply security: Outage costs in private households, Energy Policy, 39, 7825-7833.

B. Letter of instruction

Partner Geoff Petersen
Contact Geoff Petersen
T +61 2 9263 4388
gpetersen@gtlaw.com.au
Our ref GCP:GCP:1050005

GILBERT +TOBIN

L 35, Tower Two, International Towers Sydney
200 Barangaroo Avenue,
Barangaroo NSW 2000 AUS
T +61 2 9263 4000 **F** +61 2 9263 4111
www.gtlaw.com.au

27 March 2024

By email: jeff.balchin@incenta.com.au

Jeff Balchin
Managing Director
Incenta Economic Consulting

Dear Mr Balchin

South West Queensland Pipeline Form of Regulation Review

We act for APA Group (**APA**) in relation to the form of regulation review recently initiated by the Australian Energy Regulator (**AER**) for the South-West Queensland Pipeline (**SWQP**). We are seeking an expert report from you regarding the relevant economic principles for this form of regulation review.

Background

Under the National Gas Law (**NGL**), a pipeline may be either a 'scheme' or a 'non-scheme' pipeline. Some regulatory measures apply to both scheme and non-scheme pipelines – these include information disclosure obligations (Part 10 of the National Gas Rules) and rules governing access negotiations and access disputes (Parts 11 and 12, respectively). A heavier form of regulation applies to scheme pipelines, including a requirement to have an access arrangement approved by the Australian Energy Regulator (**AER**), including approved reference tariffs.

In March 2023, changes to the gas pipeline regulatory framework came into effect. These included new powers for the AER to review the form of regulation for gas pipelines and make 'scheme pipeline determinations'. The effect of a scheme pipeline determination would be to move a pipeline from a lighter form of regulation into full regulation.

The principles governing the making of scheme pipeline determinations are set out in section 112 of the NGL. Under section 112, in deciding whether to make a scheme pipeline determination the AER must consider the effect of regulating the relevant pipeline as a scheme pipeline or non-scheme pipeline on:

(a) the promotion of access to pipeline services; and

(b) the costs that are likely to be incurred by an efficient service provider; and

(c) the costs that are likely to be incurred by efficient users and efficient prospective users; and

(d) the likely costs of end users.

In doing so the AER must have regard to the national gas objective (section 23 of the NGL) and the form of regulation factors (section 16 of the NGL).

On 21 February 2024, the AER announced that it will be conducting a form of regulation review for the SWQP. The AER indicated that this is the first of a series of self-initiated form of regulation reviews the AER is planning to undertake over several years. The AER says that the SWQP was chosen as the first pipeline for a review due to its importance to the east coast gas system in transporting gas between northern and southern states.

The AER published a Discussion Paper for the SWQP form of regulation review on 6 March 2024. It has invited submissions by 27 March 2024.

Expert report

We are seeking a report setting out your expert opinion on the relevant economic principles for deciding on the appropriate form of regulation for the SWQP, including:

(a) how the potential effect of regulating the SWQP as a scheme pipeline or non-scheme pipeline should be assessed; and

(b) the appropriate economic framework for assessing the costs likely to be incurred by an efficient service provider, current and prospective users, and end-users under different forms of regulation.

Relevant background information on the SWQP is set out at **Appendix A**.

We ask that you review the requirements for expert reports set out in the Federal Court's Expert Evidence Practice Note (GPN-EXPT) (Practice Note), which includes the Harmonised Expert Witness Code of Conduct (Code) and prepare your expert report in accordance with the requirements of the Practice Note and the Code. You are expected to be objective, professional and to form an independent view regarding matters relevant to your analysis.

We require a report from you by 27 March 2024, for submission to the AER.

Yours sincerely
Gilbert + Tobin

Geoff Petersen
Partner
[redacted]

Appendix A: South West Queensland Pipeline background information

(a) Construction and early years of operation

The SWQP was originally designed and constructed to transport Cooper Basin gas from Ballera to eastern parts of Queensland.

The original terms of access to the SWQP were established through a competitive tender process run by the Queensland Government. The tender terms were later reviewed by the ACCC and the ACCC found the resulting returns to be reasonable.[1] These tender terms were subsequently reflected in ACCC-approved access arrangements for the SWQP.[2]

In the early years of its operation, demand for services on the SWQP was relatively limited. The original capacity of the SWQP was ~130TJ/day (east), however contracted capacity over the first decades of the pipeline's history never reached this level. Starting contracted capacity was roughly half the pipeline’s total capacity. Consequently, realised returns in these early years were relatively low, reflecting the downside risk associated with this investment.

Volumes on the SWQP declined significantly in the mid 2000s, as producers identified alternatives to use of the SWQP. In particular, the development of the coal seam gas (**CSG**) fields in the Surat Basin unlocked producers’ ability to enter into swaps at either end of the SWQP – greatly reducing their need for pipeline transport. Under these swap arrangements, producers at the western end of the SWQP were able to access gas at the eastern end in order to service customers in south-east Queensland. In return, producers at the eastern end could make use of Cooper Basin gas (gas at Ballera transported via the raw gas pipeline to Moomba for processing) – allowing those producers to reach southern markets without any need to use the SWQP.[3]

(b) QSN link and foundation AGL contract

In around 2007 Epic Energy, as the owner of the SWQP, entered into a foundation contract with AGL for the construction of the QSN Link (to be commissioned in 2008). This link would allow for processed Queensland gas to flow westbound on the SWQP to the southern states for the first time. This demand emerged because of the vast CSG reserves being uncovered in the Surat Basin.

Due to the under-utilisation of the SWQP at the time of this foundation contract, AGL had a high degree of countervailing power. [redacted]

---

[1] ACCC, Queensland Gas Pipeline Access Regime – Assessment of tender processes and reference tariff outcomes: A report to the National Competition Council.

[2] Approved access arrangements available at: https://www.aer.gov.au/industry/registers/access-arrangements/epic-energy-south-west-queensland-pipeline-access-arrangement-2002-04.

[3] For example, see: ‘Cooper Basin and Origin in major gas swap agreement’, Santos announcement, 6 May 2004.

(c) Expansion of the SWQP and expansion foundation contracts

Further development and commercialisation of the Surat Basin CSG reserves led to growth in demand for services to deliver this Queensland gas to southern markets.

As the largest of the Queensland producers, Origin undertook a competitive process in 2008 to seek proposals for the transport additional gas from Wallumbilla to southern markets from 2012. There were three competing proposals:

- Epic Energy proposed expanding the SWQP and QSN Link by looping them, as well as adding compression services at Wallumbilla;
- APA (not yet the owner of the SWQP) proposed a new pipeline between Wallumbilla to a mid-point on the MSP; and
- a Hunter Valley Pipeline consortium proposed a new pipeline from Wallumbilla to Newcastle.

In a competitive process, Origin Energy selected the Epic Energy option to expand the SWQP. In developing its proposal, Epic Energy sought additional shippers to secure the viability of the pipeline looping and reached an arrangement with AGL exercising its option to expand capacity under its foundation QSN Link GTA. As a result, the capacity option offered by Epic as part of the competitive tender process included capacity to meet Origin's and AGL's requirements.

The ACCC has recognised that this competitive process resulted in terms that were beneficial to those foundation shippers, reflecting the outcome of 'competition for the market'.[4]

(d) Period since 2012

In the period since 2012, the SWQP has undergone further significant expansion, reflecting changing market dynamics and increased demand. While some support has been provided by long-term contracts (including the foundation contracts discussed above), the SWQP's owners (including APA) have also taken risk in undertaking major expansions of the pipeline's capacity.

Notwithstanding the significant investment cost and risk borne by APA and previous owners of the SWQP, prices have remained in line with the foundation contract terms.

(e) SWQP investment environment

APA expects an increase in demand for pipeline services in the short term, and a need for significant investment to meet this demand. In the near term, there is expected to be an increase in demand for pipeline services from the SWQP as gas-fired electricity generation increasingly complements renewable generation and there is a transition away from coal fired generation. This will comprise an increase in pipeline throughput as well as increasing demand for ancillary services such as peaking and storage. The Gas Statement of Opportunities (**GSOO**) recently published by the Australian Energy Market Operator (**AEMO**) refers to an urgent need for investment in storage and transport capacity to reduce the risk of supply shortfalls in the southern states.[5]

---

[4] ACCC, East Coast Gas Inquiry Report, p 97.

[5] AEMO, Gas Statement of Opportunities, March 2024.

Reflecting the urgency of investment needs and rapidly changing market dynamics, timeframes for investment decisions are typically short. By way of example, we have provided a [redacted] This decision was made in 2022, for provision of capacity ahead of winter 2024.

Over the medium to longer term, the demand outlook is more uncertain. As a result of climate change policies and advances in renewable electricity generation technologies, there is likely to be a substantial decline in demand for natural gas over coming decades and well within the operational lives of existing and any new pipeline assets. However, the timing of this decline is uncertain. The GSOO sets out a number of future demand scenarios, dependent on the rate of uptake of new technologies, government policies and other factors.

Reflecting this market uncertainty, shippers are generally less willing to enter into longer term contracts for pipeline capacity.

Appendix B: Documents provided

1 AER, *Form of Regulation Review: South West Queensland Pipeline – Discussion Paper*, March 2024.

2 [redacted]

C. Curricula vitae of experts

INCENTA
ECONOMIC CONSULTING

Jeff Balchin

Managing Director

Email: [redacted]
Telephone: [redacted]

Overview

Jeff is the Managing Director of Incenta Economic Consulting. Jeff has over 30 years of experience in relation to economic regulation issues across the electricity, gas, ports, airports, telecommunications, and water infrastructure sectors in Australia and New Zealand. He has advised governments, regulators and major corporations on issues including the development of regulatory frameworks, regulatory price reviews and issues around the introduction and measurement of competition (including franchise bidding). His particular specialities have been on the application of finance principles to economic regulation, the design of incentive compatible regulation and efficient tariff structures and the drafting and economic interpretation of regulatory instruments.

In addition, Jeff has substantial experience with the application of economic and finance principles to pricing and investment appraisal and associated commercial disputes in unregulated infrastructure and non-infrastructure markets. He has also assisted with applying economic principles to competition regulation, transfer pricing and taxation issues.

Jeff has undertaken a number of expert witness assignments.

Past positions

Jeff previously was a Principal at PwC in its economics and policy team for almost 4 years, prior to that a director and partner at the Allen Consulting Group for over 13 years, and prior to that he held a number of policy positions in the Commonwealth Government. In this latter role, he was on the secretariat of the Gas Reform Task Force (1995-1996), where he played a lead role in the development of the National Gas Code.

Relevant experience

A. Economic regulation of network / monopoly activities

Assistance to parties during price reviews/negotiations

- Price review for aeronautical services for PSE4 (Client: Christchurch International Airport Limited, 2021-22) – provided advice in relation to a range of economic issues associated with setting infrastructure prices, including appropriate depreciation methods, acceptable rate of return and calculation of implied returns and techniques for forecasting expenditure. Also responsible for the overall financial modelling that fed into the calculation of prices.

- Economic regulation of ultrafast broadband (Client: Chorus NZ, 2016-ongoing) – have been advising Chorus on a range of issues associated with transitioning its ultrafast broadband activities from one that is regulated via a concession contract to a building block approach. Key matters of advice have included: the valuation of assets; the treatment of stranded asset risk (including the choice of depreciation method); treatment of its concessional government financing; allocation of shared costs and assets; cost of capital issues, technical financial modelling issues; and issues with forecasting expenditure and the design of incentive schemes.

- Cost-based price for equity post-trade services (Client: ASX Ltd, 2021-ongoing) – advised in relation to the compliance of ASX's proposed prices for the regulated services provided by its new clearing and settlement system (the CHESS replacement) with cost-based pricing principles. Key issues included: asset valuation and the relevance of intangible assets; return benchmarks; and cost / asset allocation.

- Financeability for a major electricity transmission business (Client: TransGrid, 2020-21) – provided a report accompanying an application for a rule-change demonstrating the financeability issues posed by TransGrid's pipeline of projects, and illustrating how a change to depreciation would improve its ability to attract capital.

- Tax depreciation of replaced gas distribution assets (Client: AGN, 2020-21) – estimated the extent of tax write-off for regulatory purposes that was justified by AGN's mains replacement program (provided a number of reports and financial modelling).

- Depreciation of gas transmission projects (Client: DPB, 2020-21) – provided a number of reports in support of DBP's proposals to (i) increase the number of asset groupings for regulatory depreciation purposes, and (ii) alter the remaining lives of its main assets to respond to emerging asset stranding risks.

- Regulatory depreciation method for a major container port (Client: Port of Melbourne, 2021) – provided an expert opinion about the options available to use an alternative depreciation method to create a more efficient time profile for prices.

- Asset beta for a major container port (Client: Port of Melbourne, 2020) – provided an expert opinion about the asset beta (and equity beta) for the Port of Melbourne as an input into its annual pricing submissions, which was based on an extensive analysis of the empirical evidence.

- Indicative cost-based prices for a new airport (Client: CIAL, 2019) – assisted to develop preliminary estimates of cost-based charges for a potential new NZ airport, and associated measures of financial performance.

- Depreciation for gas distribution (Client: JGN, 2019) – provided two expert reports in support of JGN's application to advance the depreciation of new investment in gas distribution assets to respond to the emerging stranding risks posed by carbon reduction policies.

- Price review for aeronautical services for PSE3 (Client: Christchurch International Airport Limited, 2015-18) – provided economic advice on a range of economic issues associated with setting infrastructure prices, including: detailed advice and modelling to underpin a reform of tariff structures to better manage CIAL's risk; appropriate depreciation methods; acceptable rate of return; approach in relation to asset / cost allocation; and techniques for forecasting expenditure. I was also responsible for the overall financial modelling that fed into the calculation of prices.

- Compliance with new regulatory regime for non-scheduled pipelines (Client: Epic SA, 2017-18) – assisted Epic SA to respond to the new regulatory regime for non-scheduled pipelines, which included advice on the economic meaning of the new regulatory requirements, modelling of an initial regulatory asset value that best complied with the regime requirements, advice on the weighted average cost of capital and assistance with determining a price that best complied with the regime requirements.

- Regulatory valuation of telecommunications local loop assets (Client: Chorus NZ, 2014) – prepared a report advising on the appropriate valuation of local loop assets for the purpose of deriving a TSLRIC price for unbundled local loop access and provided subsequent ongoing advice on the application of different methods.

- Cost allocation (Client: BHP, 2014-2016) – prepared two reports on the economic principles behind allocating costs between regulated and unregulated services during the review of tariffs for the Goldfields Gas Pipeline.

- Depreciation and financeability (Client: AGN, 2015-16) – prepared a series of reports on the use of depreciation to manage financeability issues, and its justification within the relevant legal instruments. Also advised in relation to the acceleration of depreciation for "replaced" assets.

- Depreciation and risk management (Client: ENA, 2015) – prepared a report on how depreciation could be used as a stranding-risk management tool, which included a discussion of regulatory precedents and articulation of how this role for depreciation is consistent with economic principles and the relevant legal instruments.

- AER WACC Review (Client: ENA, 2011-12) – prepared expert reports on a range of matters, including the appropriate term of the risk free rate, the appropriate term of debt and a critical assessment of the ERA's (then) method for deriving the debt risk premium.

- Design of incentives for operating expenditure efficiency (Client: ElectraNet, 2012-13) – provided expert advice on the detailed application of the incentive arrangements for operating expenditure, including the link between the incentive scheme and the forecasting method.

- Regulatory depreciation (Client: APA, 2012-13) – provided expert reports on the economic principles relevant to the depreciation method that is applied to set gas transmission charges.

- Regulatory cost of debt (Clients: Powerlink, ElectraNet and Victorian gas distributors 2011-2012) – provided a series of reports addressing how the benchmark cost of debt should be established pursuant to the National Electricity Rules and on the appropriate benchmark allowance for debt and equity raising costs.

- Real cost escalation (Client: Energex, 2009-10) – advised Energex on appropriate escalators to apply to forecasts of operating and capital expenditure over the regulatory period.

- Strategic advice, Victorian electricity distribution review and NSW gas distribution review (Client: Jemena Electricity Networks, 2009-2011) – retained as strategic adviser during the review and also provided advice on a range of technical regulatory economic issues, including on regulatory finance matters, service incentives, party contracts, allocation of costs between regulated and unregulated activities and forecasting of expenditure.

- Regulatory cost of debt (Client: Powercor Australia Limited, 2009-2010) – provided a series of reports addressing how the benchmark cost of debt should be established pursuant to the National Electricity Rules.

- Service incentive scheme (Client: Powercor Australia Limited, 2010) – assisted Powercor to quantify the financial effect that would have flowed if the former service performance incentive scheme had continued. Also prepared an expert report pointing to a material inconsistency in how the AER intended to close out the old scheme and the parameters for the new service performance incentive scheme, which was accepted by the AER.

- Input methodologies for NZ regulated businesses (Clients: Powerco NZ and Christchurch International Airport, 2009-2012) – advised in relation to the Commerce Commission's development of input methodologies, focussing asset valuation, the regulatory cost of capital, the use of productivity trends in regulation and the design of incentive-compatible regulation. Also assisted in briefing counsel in subsequent reviews.

- Commercial negotiation of landing charges (Client: Virgin Blue, 2009-2012) – economic advice to Virgin Blue during its commercial negotiation of landing charges to a number of major and secondary airports.
- Equity Betas for Regulated Electricity Transmission Activities (Client: Grid Australia, APIA, ENA, 2008) – Prepared a report presenting empirical evidence on the equity betas for regulated Australian electricity transmission and distribution businesses for the AER's five yearly review of WACC parameters for these industries. The report demonstrated the implications of a number of different estimation techniques and the reliability of the resulting estimates. Also prepared a joint paper with the law firm, Gilbert+Tobin, providing an economic and legal interpretation of the relevant (unique) statutory guidance for the review.
- Economic Principles for the Setting of Airside Charges (Client: Christchurch International Airport Limited, 2008-2013) – Provided advice on a range of economic issues relating to its resetting of charges for airside services, including the valuation of assets and treatment of revaluations, certain inputs to the cost of capital (beta and the debt margin) and the efficiency of prices over time and the implications for the depreciation of assets and measured accounting profit.
- Treatment of Inflation and Depreciation when Setting Landing Charges (Client: Virgin Blue, 2007-2008) – Provided advice on Adelaide Airport's proposed approach for setting landing charges for Adelaide Airport, where a key issue was how it proposed to deal with inflation and the implications for the path of prices over time. The advice also addressed the different formulae that are available for deriving an annual revenue requirement and the requirements for the different formulae to be applied consistently.
- Application of the Grid Investment Test to the Auckland 400kV Upgrade (Client: Electricity Commission of New Zealand, 2006) - As part of a team, undertook a review of the Commission's process for reviewing Transpower's proposed Auckland 400kV upgrade project and undertook a peer review of the Commission's application of the Grid Investment Test.
- Appropriate Treatment of Taxation when Measuring Regulatory Profit (Client: Powerco New Zealand, 2005-2006) - Prepared a series of statements on how taxation should be treated when measuring realised and projected regulatory profit.
- Application of Directlink for Regulated Status (Client: Directlink, 2003-2004) – Prepared advice on the economic efficiency of the conversion of an unregulated (entrepreneurial) interconnector to a regulated interconnector and how the asset should be valued for pricing purposes.
- Principles for the 'Stranding' of Assets by Regulators (Client: the Independent Pricing and Regulatory Tribunal, NSW, 2005) - Prepared a report discussing the relevant economic principles for a regulator in deciding whether to 'strand' assets for regulatory purposes (that is, to deny any further return on assets that are partially or unutilised).
- Principles for Determining Regulatory Depreciation Allowances (Client: the Independent Pricing and Regulatory Tribunal, NSW, 2003) - Prepared a report discussing the relevant economic and other principles for determining depreciation for the purpose of price regulation, and its application to electricity distribution. An important issue addressed was the distinction between accounting and regulatory (economic) objectives for depreciation.
- Methodology for Updating the Regulatory Value of Electricity Transmission Assets (Client: the Australian Competition and Consumer Commission, 2003) - Prepared a report assessing the relative merits of two options for updating the regulatory value of electricity transmission assets at a price review - which are to reset the value at the estimated 'depreciated optimised replacement cost' value, or to take the previous regulatory value and deduct depreciation and add the capital

expenditure undertaken during the intervening period (the 'rolling-forward' method). This paper was commissioned as part of the ACCC's review of its Draft Statement of Regulatory Principles for electricity transmission regulation.

- Application of Murraylink for Regulated Status (Client: Murraylink Transmission Company, 2003) – Prepared advice on the economic efficiency of the conversion of an unregulated (entrepreneurial) interconnector to a regulated interconnector and how the asset should be valued for pricing purposes.

- Proxy Beta for Regulated Gas Transmission Activities (Client: the Australian Competition and Consumer Commission, 2002) - Prepared a report presenting the available empirical evidence on the 'beta' (which is a measure of risk) of regulated gas transmission activities. This evidence included beta estimates for listed firms in Australia, as well as those from the United States, Canada and the United Kingdom. The report also included a discussion of empirical issues associated with estimating betas, and issues to be considered when using such estimates as an input into setting regulated charges.

- Treatment of Working Capital when setting Regulated Charges (Client: the Australian Competition and Consumer Commission, 2002) - Prepared a report assessing whether it would be appropriate to include an explicit (additional) allowance in the benchmark revenue requirement in respect of working capital when setting regulated charges.

- Pricing Principles for the South West Pipeline (Client: Esso Australia, 2001) - As part of a team, prepared a report describing the pricing principles that should apply to the South West Pipeline (this gas transmission pipeline was a new asset, linking the existing system to a new storage facility and additional gas producers).

- Likely Regulatory Outcome for the Price for Using a Port (Client: MIM, 2000) - Provided advice on the outcome that could be expected were the dispute over the price for the use of a major port to be resolved by an economic regulator. The main issue of contention was the valuation of the port assets (for regulatory purposes) given that the installed infrastructure was excess to requirements, and the mine had a short remaining life.

- Relevance of 'Asymmetric Events' in the Setting of Regulated Charges (Client: TransGrid, 1999) - In conjunction with William M Mercer, prepared a report (which was submitted to the Australian Competition and Consumer Commission) discussing the relevance of downside (asymmetric) events when setting regulated charges, and quantifying the expected cost of those events.

Major roles for regulators

- Review of the approach to regulation (Client: IPART, 2021) – reviewed IPART's proposed reforms to its approach to review regulated utility prices directed to enhancing the quality of utility proposals and forecasts. Focussed on the practical conditions required for the regime to generate the intended incentives.

- Review of financeability test (Client: IPART, 2018) – provided advice to IPART in relation to the financial metrics and target ratios that IPART proposed to use as part of its financeability test, which was released to stakeholders during the consultation process.

- Aurizon Network price review (Client: Queensland Competition Authority, 2018-19) – advised the QCA on the appropriate rate of return (discount rate) for the Aurizon Network business as in the previous review, and also advised the QCA with respect to the assessment of financeability for a regulated business and the appropriate measures to ameliorate financeability concerns.

- Aurizon Network price review (Client: Queensland Competition Authority, 2013-2014) – advised the QCA on the appropriate rate of return (discount rate) for the Aurizon Network business, which included an assessment of the relative risk of Aurizon Network compared to other infrastructure sectors, advice on the appropriate benchmark gearing level and on the benchmark debt interest rate.

- Victorian Gas Distribution Price Review (Client: the Essential Services Commission, Vic, 2006-2008) - Provided advice to the Essential Service Commission in relation to its review of gas distribution access arrangements on the treatment of outsourcing arrangements, finance issues, incentive design and other economic issues.

- Envestra Gas Distribution Price Review (Client: the Essential Services Commission, SA, 2006) - Provided advice on several finance related issues (including 'return on assets' issues and the financial effect of Envestra's invoicing policy), and the treatment of major outsourcing contracts when setting regulated charges.

- DBCT price review (Client: QCA, Qld, 2004-2006) – advice on a number of finance related issues, including the calculation of IDC for a DORC valuation, cost of debt and equity beta.

- Victorian Electricity Distribution Price Review (Client: the Essential Services Commission, Vic, 2003-2005) - Provided advice to the Essential Service Commission on a range of economic issues related to current review of electricity distribution charges, including issues related to finance, forecasting of expenditure and the design of incentive arrangements for productive efficiency and service delivery. Was a member of the Steering Committee advising on strategic regulatory issues.

- Victorian Water Price Review (Client: the Essential Services Commission, Vic, 2003-2005) - Provided advice to the Essential Services Commission on the issues associated with extending economic regulation to the various elements of the Victorian water sector. Was a member of the Steering Committee advising on strategic regulatory issues, and also provided advice on specific issues, most notably the determination of the initial regulatory values for the water businesses and the role of developer charges.

- ETSA Electricity Distribution Price Review (Client: the Essential Services Commission, SA, 2002-2005) - Provided advice on the 'return on assets' issues associated with the review of ETSA's regulated distribution charges, including the preparation of consultation papers. The issues covered include the valuation of assets for regulatory purposes and cost of capital issues. Also engaged as a quality assurance adviser on other consultation papers produced as part of the price review.

- Victorian Gas Distribution Price Review (Client: the Essential Services Commission, Vic, 2001-2002) - Economic adviser to the Essential Services Commission during its assessment of the price caps and other terms and conditions of access for the three Victorian gas distributors. Was responsible for all issues associated with capital financing (including analysis of the cost of capital and assessment of risk generally, and asset valuation), and supervised the financial modelling and derivation of regulated charges. Also advised on a number of other issues, including the design of incentive arrangements, the form of regulation for extensions to unreticulated townships, and the principles for determining charges for new customers connecting to the system.

- ETSA Electricity Distribution Price Review (Client: the South Australian Independent Industry Regulator, 2000-2001) - As part of a team, prepared a series of reports proposing a framework for the review. The particular focus was on the design of incentives to encourage cost reduction and service improvement, and how such incentives can assist the regulator to meet its statutory obligations. Currently retained to provide commentary on the consultation papers being produced by the regulator, including strategic or detailed advice as appropriate.

- Dampier to Bunbury Natural Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 2000-2002) - Provided economic advice to the Office of the Independent Regulator during its continuing assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft decision, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Represented the Office on these matters at a public forum, and provided strategic advice to the Independent Regulator on the draft decision.

- Goldfield Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 2000-2004) - Provided economic advice to the Office of the Independent Regulator during its continuing assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft decision, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Represented the Office on these matters at a public forum, and provided strategic advice to the Independent Regulator on the draft decision.

- Victorian Electricity Distribution Price Review (Client: the Office of the Regulator General, Vic, 1999-2000) - Economic adviser to the Office of the Regulator General during its review of the price caps for the five Victorian electricity distributors. Had responsibility for all issues associated with capital financing, including analysis of the cost of capital (and assessment of risk generally) and asset valuation, and supervised the financial modelling and derivation of regulated charges. Also advised on a range of other issues, including the design of incentive regulation for cost reduction and service improvement, and the principles for determining charges for new customers connecting to the system.

- Victorian Ports Corporation and Channels Authority Price Review (Client: the Office of the Regulator General, Vic, 2000) - Advised on the finance related issues (cost of capital and the assessment of risk generally, and asset valuation), financial modelling (and the derivation of regulated charges), and on the form of control set over prices. Principal author of the sections of the draft and final decision documents addressing the finance related and price control issues.

- AlintaGas Gas Distribution Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 1999-2000) - Provided economic advice to the Office of the Independent Regulator during its assessment of the regulated charges and other terms and conditions of access for the gas pipeline. This advice included providing a report assessing the cost of capital associated with the regulated activities, overall review of all parts of the draft and final decisions, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Also provided strategic advice to the Independent Regulator on the draft and final decisions.

- Parmelia Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 1999-2000) - Provided economic advice to the Office of the Independent Regulator during its assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft and final decisions, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Also provided strategic advice to the Independent Regulator on the draft and final decisions.

- Victorian Gas Distribution Price Review (Client: the Office of the Regulator General, Vic, 1998) - Economic adviser to the Office of the Regulator General during its assessment of the price caps and other terms and conditions of access for the three Victorian gas distributors. Major issues addressed included the valuation of assets for regulatory purposes, cost of capital financing and financial modelling. Principal author of the draft and final decision documents.

Development/Review of Regulatory Frameworks

- Financeability for ISP electricity transmission projects (Client: AEMC, 2023-24) – advised the AEMC on the rationale for, and design of, rules that would allow cash flows to be advanced to address financeability issues arising in relation to very large (ISP) electricity transmission projects.

- Pricing principles for non-scheduled pipelines (Client: Gas Market Reform Group, 2017) – provided advice to the Group on the range of principles that could be specified for an arbitrator if called to arbitrate a dispute on a non-scheduled pipeline, and the relative merits of the different options.

- Review of the Australian energy economic regulation (Client: Energy Networks Association, 2010-2012) – assisting the owners of energy infrastructure to engage in the current wide-ranging review of the regime for economic regulation of energy infrastructure. Advice has focussed in particular on the setting of the regulatory WACC and on the regime of financial incentives for capital expenditure efficiency, and included strategic and analytical advice, preparation of expert reports and assistance with ENA submissions.

- Review of the Australian electricity transmission framework (Client: Grid Australia, 2010-2013) – assisting the owners of electricity transmission assets to participate in the wide-ranging review of the framework for electricity transmission in the national electricity market, covering such matters as planning arrangements, the form of regulation for non-core services and generator capacity rights and charging. Has included analytical advice on policy choices, facilitation of industry positions and articulation of positions in submissions.

- Implications of greenhouse policy for the electricity and gas regulatory frameworks (Client: the Australian Energy Market Commission, 2008-2009) – Provided advice to the AEMC in its review of whether changes to the electricity and gas regulatory frameworks is warranted in light of the proposed introduction of a carbon permit trading scheme and an expanded renewables obligation. Issues addressed include the framework for electricity connections, the efficiency of the management of congestion and locational signals (including transmission pricing) for generators and the appropriate specification of a cost benefit test for transmission upgrades in light of the two policy initiatives.

- Economic incentives under the energy network regulatory regimes for demand side participation (Client: Australian Energy market Commission, 2006) – Provided advice to the AEMC on the incentives provided by the network regulatory regime for demand side participation, including the effect of the form of price control (price cap vs. revenue cap), the cost-efficiency arrangements, the treatment of losses and the regime for setting reliability standards.

- Implications of greenhouse policy for the electricity and gas regulatory frameworks (Client: the Australian Energy Market Commission, 2008) - Provided advice to the AEMC in its review of whether changes to the electricity and gas regulatory frameworks is warranted in light of the proposed introduction of a carbon permit trading scheme and an expanded renewables obligation. Issues addressed include the framework for electricity connections, the efficiency of the management of congestion and locational signals for generators and the appropriate specification of a cost benefit test for transmission upgrades in light of the two policy initiatives.

- Application of a 'total factor productivity' form of regulation (Client: the Victorian Department of Primary Industries, 2008) - Assisted the Department to develop a proposed amendment to the regulatory regime for electricity regulation to permit (but not mandate) a total factor productivity approach to setting price caps – that is, to reset prices to cost at the start of the new regulatory period and to use total factor productivity as an input to set the rate of change in prices over the period.

- Expert Panel on Energy Access Pricing (Client: Ministerial Council on Energy, 2005-2006) - Assisted the Expert Panel in its review of the appropriate scope for commonality of access pricing regulation across the electricity and gas, transmission and distribution sectors. The report recommended best practice approaches to the appropriate forms of regulation, the principles to guide the development of detailed regulatory rules and regulatory assessments, the procedures for the conduct of regulatory reviews and information gathering powers.
- Productivity Commission Review of Airport Pricing (Client: Virgin Blue, 2006) - Prepared two reports for Virgin Blue for submission to the Commission's review, addressing the economic interpretation of the review principles, asset valuation, required rates of return for airports and the efficiency effects of airport charges and presented the findings to a public forum.
- AEMC Review of the Rules for Setting Transmission Prices (Client: Transmission Network Owners, 2005-2006) - Advised a coalition comprising all of the major electricity transmission network owners during the new Australian Energy Market Commission's review of the rules under which transmission prices are determined. Prepared advice on a number of issues and assisted the owners to draft their submissions to the AEMC's various papers.
- Advice on Energy Policy Reform Issues (Client: Victorian Department of Infrastructure/Primary Industries, 2003-2009) - advice to the Department regarding on issues relating to the transition to national energy market arrangements, cross ownership rules for the energy sector, the reform of the cost benefit test for electricity transmission investments and the scope for lighted handed regulation in gas transmission.
- Productivity Commission Review of the National Gas Code (Client: BHPBilliton, 2003-2004) - Produced two submissions to the review, with the important issues including the appropriate form of regulation for the monopoly gas transmission assets (including the role of incentive regulation), the requirement for ring fencing arrangements, and the presentation of evidence on the impact of regulation on the industry since the introduction of the Code.
- Development of the National Third Party Access Code for Natural Gas Pipeline Systems Code (Client: commenced while a Commonwealth Public Servant, after 1996 the Commonwealth Government, 1994-1997) - Was involved in the development of the new legal framework for the economic regulation of gas transmission and distribution systems, with advice spanning the overall form of regulation to apply to the infrastructure and the appropriate pricing principles (including the valuation of assets for regulatory purposes and the use of incentive regulation), ring fencing arrangements between monopoly and potentially contestable activities, and whether upstream infrastructure should be included within the regime.

Licencing / Franchise Bidding

- Competitive Tender for Gas Distribution and Retail in Tasmania (Client: the Office of the Tasmanian Energy Regulator, 2001-2002) - Economic adviser to the Office during its oversight of the use of a competitive tender process to select a gas distributor/retailer for Tasmania, and simultaneously to set the regulated charges for an initial period.
- Issuing of a Licence for Powercor Australia to Distribute Electricity in the Docklands (Client: the Office of the Regulator General, Vic, 1999) - Economic adviser to the Office during its assessment of whether a second distribution licence should be awarded for electricity distribution in the Docklands area (a distribution licence for the area was already held by CitiPower, and at that time, no area in the state had multiple licensees). The main issue concerned the scope for using 'competition for the market' to discipline the price and service offerings for an activity that would be a monopoly once the assets were installed.

Assessments of the degree and prospects for competition / need for regulation

- Assessment of the merits of the coverage test in the gas regulatory regime (Client: AEMC, 2015) – advised the AEMC on whether the test contained in the gas regime for determining whether pipelines should be regulated is fit for the intended purpose, which included a detailed review of the coverage / declaration decisions to date.
- Pilbara electricity networks (Client: Public Utility Office, 2014) – provided advice to the Office on whether the applications for declaration of the Pilbara electricity networks would meet the coverage test.
- Transmission connection assets (Client: Grid Australia, 2012) – prepared an assessment of the degree of competition in the provision of transmission connection assets, which included advice on the market within which the service is provided and an assessment of the degree of rivalry (including the prospects for entry) in that market.
- South East network (Client: Kimberley Clarke, 2011) – advised whether the gas pipeline from which it is supplied would pass the threshold for regulation.
- Pilbara rail access (Client: BHP Billiton) – assisted in the preparation of expert evidence on whether the Pilbara rail infrastructure passed the test for declaration of essential infrastructure, with specific focus on the analysis of whether there would be a promotion of competition in other markets from the granting of access.
- Need for regulation of gas transmission pipelines (Client: SA Government) – advised as to whether the Moomba to Adelaide pipeline was likely to pass the threshold required for regulation under the Gas Code, focussing upon an assessment of the degree of competition for its services.

B. Pricing in non-infrastructure markets

Market reviews of the effectiveness of competition

- Review of the NZ retail banking market (Client: ANZ, 2023-24) – advising in relation to the measurement of profitability for the NZ banking sector grocery retailers and its interpretation when assessing the effectiveness of competition. Key issue is the derivation of an appropriate benchmark for returns, in turn spanning: the breadth of countries from which peer firms are sourced; the economic relevance of "intangible" assets; and whether comparisons should be made against a bottom-up estimate of the cost of capital.
- Review of the NZ grocery retailing market (Client: Foodstuffs, 2020-22) – advised in relation to the measurement of profitability for the NZ grocery retailers and its interpretation when assessing the effectiveness of competition. Key issues included: the valuation of assets; derivation of appropriate benchmarks for returns (including the relevance of "intangible" assets); and advising on how leased assets should be treated when seeking to measure economic returns (including an assessing the economic merits of IFRS16).
- Review of the NZ petrol retailing market (Client: Z Energy, 2018-19) – advised in relation to the measurement of profitability for the NZ petrol retailers and its interpretation when assessing the effectiveness of competition. Key issues included: the valuation of assets; derivation of appropriate benchmarks for returns (including the relevance of "intangible" assets); and advising on the robustness of measures of Tobin's Q (the ratio of the market value to the replacement cost of assets) for making inferences about the degree of competition in a market.
- Assessment of retail competition in Victoria and South Australia (Client: Australian Energy Market Commission) – assisted the Commission to quantity and interpret information on margins for retailers and to draw inferences about the level of competition. Also provided a peer review of

the Commission's overall assessment of the level of competition, including the Commission's overall analytical framework and the other indicators it considered.

Default/transitional regulated prices for retail functions

- ACT transitional tariff review (Client: ICRC, ACT, 2010) – advised the regulator on an appropriate method to derive a benchmark wholesale electricity purchase cost for an electricity retailer, including the relationship between the wholesale cost and hedging strategy.
- South Australian default gas retail price review (Client: the Essential Services Commission, SA, (2007-2008) – derived estimates of the benchmark operating costs for a gas retailer and the margin that should be allowed. This latter exercise included a bottom-up estimate of the financing costs incurred by a gas retail business.
- South Australian default electricity retail price review (Client: the Essential Services Commission, SA, 2007) - estimated the wholesale electricity purchase cost for the default electricity retail supplier in South Australia. The project involved the development of a model for deriving an optimal portfolio of hedging contracts for a prudent and efficient retailer, and the estimate of the expected cost incurred with that portfolio.
- South Australian default gas retail price review (Client: the Essential Services Commission, SA, 2005) - As part of a team, advised the regulator on the cost of purchasing gas transmission services for a prudent and efficient SA gas retailer, where the transmission options included the use of the Moomba Adelaide Pipeline and SEAGas Pipeline, connecting a number of gas production sources.

Market Design

- Options for the Development of the Australian Gas Wholesale Market (Client: the Ministerial Committee on Energy, 2005) - As part of a team, assessed the relative merits of various options for enhancing the operation of the Australian gas wholesale markets, including by further dissemination of information (through the creation of bulletin boards) and the management of retailer imbalances and creation of price transparency (by creating short term trading markets for gas).
- Review of the Victorian Gas Market (Client: the Australian Gas Users Group, 2000-2001) - As part of a team, reviewed the merits (or otherwise) of the Victorian gas market. The main issues of contention included the costs associated with operating a centralised market compared to the potential benefits, and the potential long term cost associated with having a non-commercial system operator.
- Development of the Market and System Operation Rules for the Victorian Gas Market (Client: Gas and Fuel Corporation, 1996) - Assisted with the design of the 'market rules' for the Victorian gas market. The objective of the market rules was to create a spot market for trading in gas during a particular day, and to use that market to facilitate the efficient operation of the system.

Transfer pricing

- Application of a netback calculation for infrastructure under the Minerals Resource Rent Tax (Client: BHPB, 2011-2013) – advised on how the arms-length price for the use of downstream infrastructure should be determined, including the valuation of assets, weighted average cost of capital and on the implications for the price of incentive compatible contracts.

Pricing strategy

- Pricing for telephone directory services (Sensis, 2012) – as part of a team, advised on how margins could be maximised for the telephone directory business in the context of falling print advertising and a very competitive digital market, informed by the application of econometric techniques.
- Effectiveness of promotional strategies (Target, 2011-2012) – as part of a team, applied econometric techniques to assess the effectiveness of Target's promotional strategies, with tools developed for management to improve profitability.
- Optimal pricing (Client: Coles, 2011-2012) – applied econometric techniques to assist Coles to set relativities of prices within "like" products and developed a method to test the effectiveness of promotional strategies.

C. Regulatory due diligence and other finance work

- Sale of Port of Melbourne (Client: a consortium of investors, 2014-16) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Sale of TransGrid (Client: a consortium of investors, 2011-12) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Sale of the Sydney Desalination Plant (Client: a consortium of investors, 2011-12) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Sale of the Abbot Point Coal Terminal port (Client: a consortium of investors / debt providers, 2010-11) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Private Port Development (Client: Major Australian Bank, 2008) - Prepared a report on the relative merits of different governance and financing arrangements for a proposed major port development that would serve multiple port users.
- Sale of Allgas gas distribution network (Client: confidential, 2006) – Prepared a regulatory due diligence report for potential acquirer of the asset.
- Review of Capital Structure (Client: major Victorian water entity, 2003) - Prepared a report (for the Board) advising on the optimal capital structure for a particular Victorian water entity, taking account of the likely impact of cost-based regulation.

D. Expert Witness Roles

- Roaming fee between operators of toll-roads (Client: ConnectEast, 2021-23): provided an expert opinion on how the fee that one toll road (home operator) charges another (away operator) for recovering tolls when account holders "roam" on the away operator's toll road should be calculated (in conformity with the CityLink Act).
- Commercial dispute around service fee (Client: ZEN Energy, 2022-23): provided an expert opinion about the calculation of certain elements of a service fee, including the cost of procuring a bank guarantee and the appropriate profit margin.
- Access price for a gypsum loading facility at a port (Client: Gypsum Resources Australia, 2019-20) – provided an expert opinion about the appropriate cost-based price for the loading service in an access arbitration. Key issues included: the appropriateness of price benchmarking

versus cost-based pricing; asset valuation (in the context of a very old facility); estimation of the required commercial return; the method for forecasting expenditure (including the sharing of risk); and the effect of different forms of price escalation.

- Measurement of short run marginal cost (SRMC) and assessment of market power in electricity generation (Client: Economic Regulatory Authority, WA, 2020-21) – provided expert evidence in support of the ERA WA's action against Synergy (a major generator) before the Electricity Review Board that Synergy had (i) submitted offers into the energy market in excess of SRMC, and (ii) that Synergy had / had exercised market power. Focus of evidence was on (i) concept of SRMC; (ii) the measure of gas costs for the purpose of SRMC, and (iii) whether Synergy had / had exercised market power.
- Stamp duty assessment for a gas distributor (Client: confidential, 2020-21) – provided an expert report about whether the attraction of custom for a gas distributor may create value and so give rise to an intangible asset.
- Assessment of the market / lessening of competition for a container port (Client: NSW Ports, 2019-20) – provided expert evidence in the ACCC's actions to strike down certain agreements between NSW Ports and the NSW Government as lessening competition. Focus of the evidence was on the role of the broader logistics chain (including land transport costs) in defining the geographic market for the services, and the effect of these factors for the financial viability for an alternative container port at Port of Newcastle.
- Arbitration of prices for the Vanuatu electricity utility (Client: UNELCO (asset owner), 2019-21) – provided expert evidence in a commercial arbitration under the concession agreement on a range of economic issues relevant to the arbitration, including the cost of capital, the regulatory valuation of assets (including the treatment of accrued provisions), the form of price control and the determination of operating expenditure allowances.
- Tax consequences of customer contributions (Client: VPN, 2017-19) – provided expert evidence about the regulatory treatment of customer contributions and related matters for a dispute in the Federal Court with the Tax Commissioner about whether these contributions should be assessed as income.
- Goldfields gas pipeline price review (Client: BHP, 2017) – provided expert evidence to the judicial review on the economic principles around whether a "true-up" is permitted when be there is a delay in the commencement of a regulatory period under the National Gas Rules.
- Goldfields gas pipeline price review (Client: BHP, 2014) – provided an expert report on economic principles associated with the allocation of costs between regulated and unregulated assets.
- Kapuni gas contract dispute (Client: Vector, 2013-2015) – provided expert evidence for the arbitration addressing a number of economic issues with determining a fair and reasonable price for the (raw) Kapuni gas, including the overall economic interpretation of the bargain, an appropriate netback price for gas processing, retail margins, value of gas flexibility and interpretation of discovered gas supply arrangements.
- Abbot Point Coal Terminal Pricing Arbitration (Client: Adani, 2013) – prepared a number of expert reports for the arbitration on economic issues arising from the application of the cost-based formula in the pricing agreement, including the economic meaning of key terms, the valuation of assets (and specifically the role and calculation of interest during construction), the quantification of transaction costs of raising finance and the calculation of the required rate of return (most notably, the benchmark cost of debt finance).

- New Zealand Input Methodologies (Clients: Powerco and Christchurch International Airport Limited, 2009-2012) – prepared expert report for both clients on a range of economic issues, including the valuation of assets, weighted average cost of capital, cost allocation, the regulatory treatment of taxation and interpretation of the new purpose statement in the Commerce Act. Appeared as an expert before the Commerce Commission in the key conferences held during the review. Also assisted the clients in their subsequent merit reviews of the Commission's decision.

- Victorian gas market dispute resolution panel (Client: VENCorp, 2008) – prepared an expert report and was cross examined in relation to the operation of the Victorian gas market in the presence of supply outages.

- Consultation on Major Airport Capital Expenditure Judicial Review (Client: Christchurch International Airport, 2008) – prepared an affidavit for a judicial review on whether the airport consulted appropriately on its proposed terminal development. Addressed the rationale, from the point of view of economics, of separating the decision of 'what to build' from the question of 'how to price' in relation to new infrastructure.

- New Zealand Commerce Commission Draft Decision on Gas Distribution Charges (Client: Powerco, 2007-2008) – prepared an expert statement about the valuation of assets for regulatory purposes, with a focus on the treatment of revaluation gains, and a memorandum about the treatment of taxation for regulatory purposes and appeared before the Commerce Commission.

- Sydney Airport Domestic Landing Change ACCC Arbitration (Client: Virgin Blue, 2007) – prepared two expert reports on the economic issues associated with the structure of landing charges.

- New Zealand Commerce Commission Gas Price Control Decision – Judicial Review to the High Court (Client: Powerco, 2006) – provided four affidavits on the regulatory economic issues associated with the calculation of the allowance for taxation for a regulatory purpose, addressing in particular the need for consistency in assumptions across different regulatory calculations.

- Victorian Electricity Distribution Price Review: Appeal to the ESC Appeal Panel (Client: the Essential Services Commission, Vic, 2005-2006) – prepared expert evidence on (i) the workings of the ESC's service incentive scheme and the question of whether the scheme was likely to deliver a windfall gain or loss to the distributors, and (ii) the workings of the ESC's tariff basket form of price control, with a particular focus on the ability of the electricity distributors to rebalance prices and the financial effect of the introduction of 'time of use' prices in this context.

- New Zealand Commerce Commission Review of Information Provision and Asset Valuation (Client: Powerco New Zealand, 2005) - Appeared before the Commerce Commission for Powerco New Zealand on several matters related to the appropriate measurement of profit for regulatory purposes related to its electricity distribution business, most notably the treatment of taxation in the context of an incentive regulation regime.

- Duke Gas Pipeline (Qld) Access Arrangement Review – Appeal to the Australian Competition Tribunal (Client: the Australia Competition and Consumer Commission, 2002) - Prepared expert evidence on the question of whether concerns of economic efficiency are relevant to the non price terms and conditions of access.

- Victorian Electricity Distribution Price Review: Appeal to the ORG Appeal Panel (Client: the Office of the Regulator General, Vic, 2000) – Provided expert evidence to the ORG Appeal Panel on the questions of (i) whether the distribution of electricity in the predominantly rural areas carried greater risk than the distribution of electricity in the predominantly urban areas and (ii) the implications of inflation risk for the cost of capital associated with the distribution activities.

Qualifications and memberships

- Bachelor Economics (First Class Honours) University of Adelaide
- CEDA National Prize for Economic Development

Ray Challen

Senior Associate

Email: [redacted]

Telephone: [redacted]

Overview

Ray has over 25 years of experience in economic regulation of utilities infrastructure as a consultant, executive public servant, and regulator. This includes 10 years of economic-reform, regulation, executive leadership and regulatory-board positions in the Western Australian public service and, prior to this, some 20 years of research and consulting positions across economic regulation, public policy, environmental science and natural resource management.

Prior to this Ray had a career in consulting in economics and public policy, leading economics consulting teams in Perth, once with the Allen Consulting Group and once with PricewaterhouseCoopers. These teams held positions in both the local and national market for consulting services characterised by reputations for rigorous and impartial advice and for respect from both government and corporate clients.

Past positions

- Incenta Economic Consulting (2023 to date)
  Senior Associate

- Economic Regulation Authority of Western Australia (2017 to 2022)
  Governing Board Member

- Department of Finance, Government of Western Australia (2012 to 2017)
  Deputy Director General – Public Utilities Office (Coordinator of Energy) and Economic Reform

- PricewaterhouseCoopers (2009 to 2012)
  Executive Director and Principal – Economics and Policy

- Allen Consulting Group (2001 to 2009)
  Senior Manager, Associate Director, Director

- Environmental Resource Management Australia (1998 to 2001)
  Senior Economist

- University of Western Australia (1995 to 1998)
  PhD student and casual lecturer

- Woodward-Clyde (formerly Australian Groundwater Consultants) (1988 to 1994)
  Environmental Scientist and Senior Environmental Scientist

Education

- Degree Qualifications

Doctor of Philosophy (Agricultural Economics), University of Western Australia 1999

Master of Science (Natural Resource Management), University of Western Australia 1994

Bachelor of Science in Agriculture (Hons), University of Western Australia 1989

- Other Qualifications

Graduate, Australian Institute of Company Directors.

Recent relevant experience

Incenta Economic Consulting (Commenced September 2023) - Senior Associate

After a 12 month "career break", Ray has joined Incenta as a Senior Associate to undertake projects for clients in competition economics and economic regulation.

Economic Regulation Authority of Western Australia (August 2017 to August 2022) - Governing Board Member

The Economic Regulation Authority has responsibility in Western Australia for access regulation for energy infrastructure (under the National Gas Law as applied in Western Australia and the Western Australian Electricity Networks Access Code); electricity and gas market compliance monitoring and enforcement; electricity and water industry licensing under State-based industry regulation schemes; and a broad function of independent inquiries on matters of economic policy and public sector administration.

Major issues addressed during Ray's five year term on the board of the Economic Regulation Authority included investigation and successful prosecution of a state-owned electricity business for anti-competitive conduct; regulatory decisions for gas pipelines involving a shortening of expected pipeline lives and a bringing forward of depreciation having regard to the timing of net-zero objectives in climate change policy; and several significant compliance monitoring, investigation and enforcement decisions for the Western Australian Wholesale Electricity Market.

Department of Finance, Government of Western Australia (2012 to July 2017) Deputy Director General - Public Utilities Office and Economic Reform

In 2012, Ray commenced with the Department of Finance to lead the newly formed Public Utilities Office, with the task of re-building the policy advice capability within Government in energy and utility services. This involved substantial reform of the business inherited from the preceding Office of Energy. This required changing the emphasis of the business from one of managing grant and subsidy schemes to one of policy advice and innovation in regulatory and market reform, with a commensurate change in staff and skills mix within the constraints of public sector practices. In late 2013, the Economic Reform business of the Department of Treasury was transferred to the

Department of Finance with a similar intent of re-building policy capability within government in regulatory reform and microeconomic reform.

The policy capabilities of the Public Utilities Office and Economic Reform were successfully built to the point of being highly regarded across government. Examples of substantive achievements during my term as Deputy Director General are as follows.

- Transfer of responsibility for operation of the electricity system and electricity market from State-based entities to the nationally operating Australian Electricity Market Operator.

- Delivery of reforms to the capacity market elements of the Western Australian Wholesale Electricity Market, with the reforms delivery improved capacity pricing signals for investment and retirement of generation capacity.

- Developing the policy and legislation package to transfer regulation of the electricity sector to the national legislative framework to be applied as uniform national legislation in Western Australia (which did not proceed after a change of government).

- Implementation of the Government decision to merge the Verve and Synergy businesses in 2013 within a tight time frame and with a supporting regulatory framework to limit anti-competitive effects.

- Establishing a more rigorous basis for determining the value of subsidies paid for delivery of electricity services of residential and small-business customers.

- Substantially improving the quality of commercial advice provided to government on the operations and performance of the State-owned energy businesses (Synergy, Western Power and Horizon Power).

PricewaterhouseCoopers (2009 to 2012) Executive Director and Principal - Economics and Policy

Ray led an economics consulting team in Perth, integrated with PwC's broader management consulting practice.

Consulting work focussed on regulating access and prices for energy and transport infrastructure, reforming government trading enterprises, regulatory impact assessments, and competition law. Principal roles involved:

- advising government policy agencies, economic regulators, government businesses and corporate owners and users of energy and transport infrastructure on access-related matters;

- advising major mining companies on regulatory matters, including infrastructure access and minerals taxation.

- providing expert evidence and statements on competition and trade practices matters and disputes;

- undertaking due diligence studies in transactions involving regulated energy and infrastructure businesses;

- undertaking industry-reform and business-reform studies in sectors dominated by government businesses, or heavily regulated by government.

Allen Consulting Group (2001 to 2009) Senior Manager, Associate Director and then Director

In 2001 Ray joined the Allen Consulting Group, a boutique economics and policy consulting firm of about 60 staff nationwide, with the role of establishing a Perth office of the firm.

Examples of major assignments in this period are:

- Advice on reform of the racing and wagering industry in Western Australia.

- Advising the Economic Regulation Authority (and its predecessor agencies) on initial regulatory decisions under new third-party access regimes for gas, rail and electricity infrastructure. This advice served to establish many of the decision-making protocols that are still applied by the Authority. Advice included the initial regulatory decision on access to the Dampier to Bunbury Natural Gas Pipeline in difficult circumstances where the private owners of the pipeline had substantially over-paid for the asset and any sensible regulatory determination would inevitably place the business in financial distress - an outcome that did ultimately eventuate with long term repercussions for the Western Australian gas market, although the regulatory decision withstood challenge in the Supreme Court.

- Advice to the Western Australia government on electricity industry reform and establishment of the Western Australian Wholesale Electricity Market.

- Design of pricing models and strategies for cost recovery in provision of government services.