Financial Information Disclosed by Gas Pipelines in Australia

UNDER PART 23 OF THE NATIONAL GAS RULES

PREPARED FOR

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Notice

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Executive Summary

This report was commissioned by the Department of the Environment and Energy as part of a review of the effectiveness of the current framework of economic regulation applying to gas pipelines. In Australia, some gas pipelines must submit their access terms to the Australian Energy Regulator (AER), and the AER has the authority to vary those terms, including price. Other pipelines, including several of the largest pipelines in Australia, are "uncovered" (or "non-scheme") and have not been subject to economic regulation until relatively recently. Shippers seeking access to uncovered pipelines had no recourse if they were unable to negotiate acceptable access terms. Recent changes to the National Gas Rules ("Part 23") now require uncovered pipeline operators to report certain financial and other information, and provide a system of binding arbitration if a shipper is unable to negotiate acceptable access terms. The goal of these changes is to enhance shippers' ability to negotiate access terms, including by providing them with information on the historical financial performance of the pipelines.

This report analyses the first set of information disclosed by certain uncovered pipelines under the new rules. We have compiled the information and calculated a variety of benchmark access prices. Since the information disclosed under Part 23 relates to pipelines' costs, the pricing benchmarks we calculate are cost-based. As we compiled the Part 23 financial information, we identified several areas where additional information would be useful to shippers, or where additional transparency would be beneficial.

The objective of Part 23 is "to facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which, for the purposes of this Part, is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market".[1] We think that the term "workably competitive market" refers to the operation of real-world markets in which competition functions reasonably well, as distinct from hypothetical markets with "perfect" competition, such as may be described in textbooks.

A workably competitive market is one where economic regulation may well not improve on the outcomes being delivered by (albeit imperfect) competition, because of the adverse consequences associated with a regulator setting prices too low or too high. In hypothetical markets with perfect competition, price equals marginal cost, and there is only one price for any given service or product. In real markets, prices will often be greater than marginal cost (otherwise fixed costs would not be recovered and producers would permanently operate at a loss), and often different customers pay different prices for the same or similar products. Prices will never be less than short-run avoidable costs, but will often be high enough to cover fixed costs and a return on sunk investment. When there is excess demand, prices will rise until new capacity is brought on. In the short term, before investment can respond, prices may rise above the long-run cost of entry as buyers compete for scarce supply.

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[1] National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 546(1).

In real markets, producers sometimes earn high profits and sometimes make losses as market conditions change. Nonetheless, when making investments, producers expect to earn a fair return on that investment. If they expected less than a fair return, they would not invest; and they would not expect more than a fair return because additional entry would compete it away. Thus pricing benchmarks based on cost can be a guide to outcomes in a workably competitive market, but only a guide. When there is competition for scarce capacity, the cost of entry and shipper valuation of capacity will be more relevant. In contrast, when there is excess capacity prices may not support a return on sunk investment. Therefore a shipper negotiating access, or an arbitrator determining a dispute, will need to have regard to factors other than the pipeline's cost. Nonetheless, this report focuses on the information disclosed under Part 23 and therefore concentrates on cost-based pricing benchmarks.

We have created a set of cost-based pricing benchmarks using the Part 23 financial information. Our benchmarks include incremental cost, fixed operating costs and a return of and on invested capital, as well as income tax. Almost all of a pipeline's operating costs are fixed, and thus need to be allocated to individual shippers using the pipeline to derive cost-based pricing benchmarks. Furthermore, some pipelines provide more than one service, so costs may need to be allocated across services as well as across shippers. For each of the components that go into a cost-based pricing benchmark, there are several options for input data available from the Part 23 financial information, and there are different options for methodology to calculate cost-based pricing benchmarks from the inputs. Different options can result in significantly different results in terms of a pricing benchmark, even though all of them are based on cost. Our report provides calculations of different pricing benchmarks to illustrate the impact of choosing different input data and/or calculation methodologies. However, there are many possible permutations of input data and/or calculation methodologies and we have not calculated a "range" of cost-based pricing benchmarks for each pipeline.

In reviewing the Part 23 financial information for the purpose of calculating pricing benchmarks, we observe that there are inconsistencies in the financial information reported under Part 23 across pipelines, as well as across different tables within the AER Template completed by the same pipeline. Across pipelines, we find that a particular item of information may include different types of costs for one pipeline than for another or might be calculated under different sets of assumptions. Across different tables within the AER Template, some items of information are included in more than one of the tables. We find that for some pipelines, particular items of information that are reported more than once may not be the same value in each table where they are reported.

Inconsistencies in the Part 23 financial information across pipelines arise for a number of reasons, including that: some service providers report estimated information instead of actual recorded information; service providers apply different assumptions in otherwise similar calculations; service providers apply different allocators to allocate shared assets and expenses; and some service providers include additional information under "catch-all" categories such as "other assets" or "other shared costs". Inconsistencies across different tables for the same pipeline can be due to a lack of clarity in the AER Guideline and/or inconsistencies within the AER Template.

The lack of clarity and the inconsistencies in the reported information mean that greater reliance has to be placed on the Basis of Preparation documents published by each pipeline rather than on the AER Guideline, in order to understand what the reported information represents and how it was derived. It can be challenging to fully understand and identify the different cost components for a pipeline. Furthermore, calculations of cost-based pricing benchmarks can result in a wide range of outcomes. Given the nature of pipeline operations, it is to be expected that a range of cost-based pricing benchmarks that spans avoidable cost, fixed cost, and investment cost will be wide. However, the wide range also results from a lack of clarity in the reported information.

We also observe that, since information reported under Part 23 is historical information, it might not reflect the expected future costs of operating pipeline services.

Further, the Part 23 financial information provides shippers with an understanding of the costs of operating a pipeline, but not the value of pipeline capacity. As explained above, the value of pipeline capacity can also be an important consideration for determining an access price.

We consider that disclosing additional information would be valuable because it would facilitate shippers being able to compare offered prices against benchmarks that shippers calculate based on the pipeline's costs, and would allow them to test assumptions that the pipelines have made. For example, pipelines must make an assumption about the required rate of return each year over the life of the pipeline, but are not required to report that assumption. Similarly, pipelines report a dollar amount of notional tax liability each year, but do not report how that figure is calculated. We also propose some recommendations around changes to the existing framework for information disclosure (ie, the AER Template and Guideline) so that the information disclosed currently can be made clearer and more consistent.

In this report, we have also compared the scope of information disclosed by uncovered pipelines under Part 23 with the scope of information disclosed by covered pipelines under Parts 8–12 of the National Gas Rules as part of their access proposals. While there is some overlap, the two sets of information are different in two important respects. First, uncovered pipelines disclose only historical information (ie, recorded costs in prior periods), whereas access prices determined for covered pipelines focus on forecast information (ie, forecasts of costs in future periods). Second, uncovered pipelines report annually, with some historical information required to be reported for the entire history of the pipeline, whereas covered pipelines prepare an access proposal every five years. There is some overlap, because along with their forecasts of future costs, covered pipelines submit information on historical costs. The details of historical cost reporting are not the same between covered and uncovered pipelines. To obtain the entire history of costs for a covered pipeline a shipper would have to compile regulatory determinations across different regulatory periods, and the information is typically more complicated to review and use. Covered pipelines are not required to report historical information on revenues or returns.

I. Introduction

1. Traditionally, some gas pipelines in Australia have been subject to price regulation while others have not. Regulated pipelines are termed "scheme pipelines" or "covered pipelines", and have been subject to either "full regulation" or "light regulation", with the relevant rules contained in Parts 8-12 of the National Gas Rules (NGR). Covered pipelines are required to publish a reference access price and, in the case of full regulation pipelines, the Australian Energy Regulator[2] (AER) is responsible for approving a reference price. In contrast, non-scheme (or "uncovered") pipelines were until recently not subject to any requirements for publishing access prices or having access prices approved.

2. Shippers can apply to the National Competition Council (NCC) for a pipeline to be covered.[3] The NCC will make a recommendation to the relevant Minister, having regard to the "coverage criteria". The pipeline coverage criteria include that access to the pipeline would promote a material increase in competition in at least one upstream or downstream market.[4] A covered pipeline can also apply to the NCC to seek to change the coverage status of a pipeline.[5]

3. While all pipelines are free to negotiate access with prospective shippers on a commercial basis, prospective shippers on covered pipelines have the right to obtain access (to the reference service(s)) at the published reference price.[6] Until recently, prospective shippers on uncovered pipelines had no immediate recourse if commercial negotiations did not result in agreement with the pipeline.[7]

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2 The Economic Regulation Authority of Western Australia (ERA) is responsible for regulating gas pipelines in Western Australia under the NGR. Elsewhere in Australia this is the responsibility of the Australian Energy Regulator.

3 Section 92 of the National Gas Law.

4 Section 15 of the National Gas Law.

5 Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 31.

6 References services are a specific service offered by a service provider, where the regulator has approved tariff and non-tariff terms and conditions (AEMC, Regulation of covered pipelines, Rule determination, 14 March 2019, p. 30). The NGR requires the regulator to apply a test in determining whether pipeline services are reference services that reflects the trade-off between the "benefits that reference services provide to prospective users" and the "cost and regulatory burden of the ex ante determination of reference services and corresponding reference tariff and non-tariff terms and conditions" (AEMC, Regulation of covered pipelines, Rule determination, 14 March 2019, p. 35).

7 Prospective shippers could apply for a declaration that the pipeline should become covered. However, there have been few successful applications for coverage. The Vertigan Report notes that "[c]onsultation suggests the few applications for coverage is likely reflective of the costs and time associated with

4. In 2017, the Gas Market Reform Group (GMRG) developed a new information disclosure and arbitration framework for non-scheme pipelines.[8] This new framework requires the pipelines to disclose certain pipeline-specific information that will be useful for prospective shippers in negotiating an access price. The new framework also creates the right for shippers to submit an access request to arbitration, with the arbitrator's decision as to the terms of access binding on the pipeline. This new framework is contained in Part 23 of the NGR. Non-scheme pipelines published their first information disclosures under Part 23 for the six-month period 1 January 2018 to 30 June 2018. Subsequent filings will be annual, providing financial information on a fiscal year basis.[9]

5. The Department of the Environment and Energy has retained The Brattle Group to review the Part 23 financial information disclosures of fourteen transmission pipelines ("Part 23 pipelines"),[10,11] and to address the following questions:

   - How might the Part 23 financial disclosures be useful to shippers in negotiating an access price and to an arbitrator in setting an access price?
   - Is the information disclosed under Part 23 consistent across the fourteen pipelines to which Part 23 applies, and is the information usable or are there gaps?
   - What benchmarks for a reasonable access price can be calculated from the Part 23 financial disclosures for these fourteen pipelines?
   - How does the scope of information disclosure under Part 23 compare to the scope of information disclosure under Parts 8-12 of the NGR?

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putting in an application, the perception of the improbability of success and the uncertainty associated with how the AER will determine tariffs should the pipeline be regulated" (Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 57).

8 See Gas Market Reform Group, "Gas pipeline information disclosure and arbitration framework – Final Recommendation", June 2017. Further details are discussed in section II.

9 AER Guideline, p. 7.

10 Some transmission pipelines are exempt from the reporting requirements under Part 23, for example if they provide service to a single shipper. Transmission pipelines with less than 10 TJ/day average daily injection over the preceding 24 months are exempt from usage and financial information disclosure under Part 23. We were asked to examine Part 23 financial disclosures of the following owners and fourteen non-exempt transmission pipelines: APA Group (Berwyndale to Wallumbilla Pipeline; Moomba to Sydney Pipeline; South East South Australia Pipeline; South West Queensland Pipeline; Wallumbilla to Gladstone Pipeline; and the uncovered part of the Goldfields Gas Pipeline); Jemena (Darling Downs Pipeline; Eastern Gas Pipeline; Queensland Gas Pipeline; and VicHub Pipeline); SEA Gas (Port Campbell to Adelaide Pipeline; and Port Campbell to Iona Pipeline); EPIC (Moomba to Adelaide Pipeline System); and Palisade (Tasmanian Gas Pipeline).

11 Distribution pipelines can have obligations under Part 23. None of the pipelines we examine in this report are distribution pipelines. We have not considered whether the discussion of using financial information disclosed under Part 23 in the context of access negotiations would apply in the same way to distribution pipelines as to transmission pipelines.

6. We understand that this report will be an input for officials assessing the effectiveness of the current framework and preparing a draft Regulation Impact Statement due to be published at the end of 2019.

7. Our report is set out as follows. We first provide an overview of the policy goal of Part 23 and the framework of financial information disclosure under Part 23 in section II. We discuss our framework for using the Part 23 financial information to calculate access pricing benchmarks in section III. We then analyse the financial information disclosed by fourteen pipelines for the period 1 January 2018 – 30 June 2018 in section IV and apply the reported information in our pricing benchmark calculations in section V. In section VI we discuss the consistency and usability of the Part 23 financial information, and provide an estimate of the costs to service providers of producing the information and to shippers of using the information. We were also asked to compare information disclosure by uncovered pipelines under Part 23 with information disclosure by covered pipelines under Parts 8–12. Our comparison is detailed in section VI. Lastly, we propose some recommendations aiming at improving the consistency and usability of the Part 23 financial information disclosure in section VIII. Our report also includes a number of Appendices which contain supporting materials.

II. Financial information disclosure under Part 23

A. Policy goal of Part 23

8. In 2016, the Australian Competition and Consumer Commission (ACCC) completed its *"Inquiry into the East Coast Gas Market",* which found evidence of pipeline operators engaging in monopoly pricing. The ACCC stated that "the rates of return some pipeline operators have assumed when determining the price of access to the incremental investments that have occurred in the last three years are 1.4–20 times higher than the benchmark return on equity the Australian Energy Regulator (AER) has estimated in gas regulatory decisions over this period, despite these investments being usually fully underwritten by shipper GTAs [gas transportation agreements]. They are also substantially higher than the return adopted in the winning bid for the NGP [Northern Gas Pipeline]".[12]

9. The ACCC concluded that "competition is not posing as an effective constraint on the behaviour of pipeline operators as might be expected and that the gas access regime, in its current form, is also failing to impose an effective constraint on pipeline operators, either directly through regulation or indirectly through the threat of regulation".[13] The ACCC also noted that "[t]he current test for regulation under the National Gas Law (NGL) (the coverage criteria) is not designed to address the market failure that has been observed in this Inquiry [the ACCC's Inquiry], that is, monopoly pricing that results in economic inefficiencies with little or no effect on the level of competition in dependent markets".[14] The ACCC subsequently recommended that the COAG (Council of Australian Governments) Energy Council "should agree to replace the current test for the regulation of gas pipelines (the coverage criteria) in the NGL with a new test".[15]

10. Following the findings from the ACCC's Inquiry, the COAG Energy Council directed the Independent Chair of the Gas Market Reform Group (GMRG), Dr Michael Vertigan AC, to examine the current regulatory test for the regulation of gas pipelines.[16]

11. In December 2016, Dr Vertigan published his findings, which stated:

> *"The widespread experience of shippers is that pipeline operators are exercising their market power to the detriment of efficient outcomes in upstream and downstream*

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12 ACCC, "Inquiry into the east coast gas market", April 2016, pp. 8–9.

13 ACCC, "Inquiry into the east coast gas market", April 2016, p. 111.

14 ACCC, "Inquiry into the east coast gas market", April 2016, p. 18.

15 ACCC, "Inquiry into the east coast gas market", April 2016, p. 20.

16 GMRG, "Gas pipeline information disclosure and arbitration framework – Final Recommendation", June 2017, p. 1.

markets. There is some indication, and a widespread perception, that pipeline operators are using their market power to engage in monopoly pricing.

The principal problem is that parties negotiating for pipeline access and services have unequal levels of bargaining power and information. Consequently, the examination has focused on the most effective and least onerous ways to address this negotiating imbalance, with the objective of delivering more competitive outcomes in the market for pipelines services".[17]

12. Dr Vertigan explored the option of a change of the coverage test with stakeholders. However, the Vertigan report concluded that "[w]hile the test for pipeline coverage could be amended to introduce a market power criterion, it is concluded that the objective of addressing the negotiating imbalance could more effectively be addressed by requiring binding arbitration where commercial negotiations fail".[18]

13. Dr Vertigan made a number of recommendations, seeking to "reduce the imbalance in negotiating power, by instituting a credible threat of intervention in the event commercial negotiations break down".[19] Dr Vertigan recommended that (i) "the disclosure and transparency of pipeline service pricing and contract terms and conditions be enhanced, including requiring the provision of information on the full range of pipeline services which are available or sought", (ii) "a framework for binding arbitration, available to all open access pipelines in the event parties are unable to reach a commercial agreement, be introduced into the National Gas Law", and (iii) "the GMRG be tasked with developing a detailed design of the disclosure and transparency requirements and of the arbitration framework".[20] In addition, Dr Vertigan recommended that no change be made to the coverage test.

14. In June 2017, following Dr Vertigan's recommendations, the GMRG published its final recommendations on the design of the new information disclosure and arbitration framework.[21]

15. In August 2017, Part 23 of the NGR were introduced. Part 23 sets out the new information disclosure obligations and the arbitration framework.

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17 Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 99.

18 Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 13.

19 Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 99.

20 Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 100.

21 GMRG, "Gas pipeline information disclosure and arbitration framework – Final Recommendation", June 2017.

16. Part 23 states that "[t]he objective of this Part is to facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which, for the purposes of this Part, is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market".[22] The over-arching National Gas Objective (NGO) is to "promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas".[23]

17. The objective set out in Part 23 is accompanied by a set of rules requiring service providers of non-scheme pipeline to make public certain information. Part 23 also provides for an arbitration process to resolve access disputes, and principles that the arbitrator must have regard to when determining access disputes. The information disclosure requirement applied to uncovered pipelines under Part 23 is summarized in the next section.

B. Part 23 disclosure requirement

18. Rule 552 of the NGR requires that a service provider for a non-scheme pipeline publish the following: service and access information, standing terms, financial information and weighted average price information. Service and access information refers to general pipeline information such as location, nameplate capacity, and historical injection and withdrawal quantities. Standing terms include price and other terms and conditions for each pipeline service, as well as the methodology used to calculate the standing price. The NGR do not specify that an offer to pay for access at the standing terms must be accepted, but, given the availability of binding arbitration, we assume that such an offer would be accepted provided that significant additional costs (ie, investment) would not be incurred in providing access.

19. Financial information and weighted average price information must be prepared and published in accordance with an AER guideline. The AER published this guideline ("Financial Reporting Guideline for Non-Scheme Pipelines" or the AER Guideline), as well as a financial reporting template (the AER Template) and an explanatory statement ("Financial Reporting Guideline for Non-Scheme Pipelines Explanatory Statement" or the AER Explanatory Statement) in December 2017.

20. The AER Guideline (i) "provide[s] for the publication of financial information about each non-scheme pipeline", (ii) "specif[ies] the level of detail of information required", (iii) "specif[ies] any accounting standards that apply to the reported information", and (iv) "specif[ies] the level of audit assurance required for the financial information".[24] In particular, the AER Guideline requires service providers of non-scheme pipelines to publish three sets of financial statements: (i) a statement of pipeline revenues and expenses, (ii) a

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22 National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 546(1).

23 Section 23 of the National Gas Law.

24 AER Guideline, p. 1.

statement of pipeline assets, and (iii) pipeline information.[25] The AER Guideline also specifies "the methods, principles and inputs to be used" in the calculation of the weighted average price information.[26]

21. With regard to asset values, the AER Guideline requires that service providers report the value of pipeline assets under two approaches: the "book value" method and the "recovered capital" method (RCM).[27]

22. The book value method calculates depreciated book value, taking into account additions and disposals. Service providers are required to report (i) construction costs (or acquisition cost if the asset was acquired) as the opening value of the pipeline assets,[28] and (ii) accumulated capital expenditure, disposals and depreciation since construction or acquisition of the pipeline assets.[29] It is not clear from the AER Guideline if the reporting of acquisition cost versus construction cost is a choice for service providers that acquired a pipeline.

23. The RCM "calculates the depreciated cost of constructing the pipeline, with the depreciation component reflecting the return of capital generated since the pipeline was constructed (ie, revenue less operating expenditure less the return on capital [at an assumed opportunity cost rate] less net tax liabilities)".[30] Thus, under the RCM, return of capital is calculated as the residual once operating expenses and an assumed return *on* capital (and taxes) are netted from revenues. For the calculation of the RCM, service providers are required to report the construction cost of the pipeline assets, capital expenditure, and an estimate of the return of capital each year since the construction date of the pipeline assets. The estimation of the return of capital requires historical revenue, operating expenses, an assumed return on capital[31] and an estimate of tax liabilities.[32] The AER notes that the RCM arises from rule 569(4) of Part 23, which states:

> *(a) the value of any assets used in the provision of the pipeline service must be determined using asset valuation techniques consistent with the objective of* [Part 23: namely, prices that reflect the outcomes of a workably competitive market]*; and*

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25 AER Explanatory Statement, p. 12.

26 AER Guideline, p. 1.

27 AER Explanatory Statement, p. 4.

28 AER Explanatory Statement, p. 4; AER Guideline, p. 12.

29 AER Guideline, p. 12.

30 AER Explanatory Statement, p. 4.

31 The return on capital captures the opportunity cost of the investment in pipeline assets (ie, to invest in the pipeline assets, pipeline owners forgo the opportunity to invest elsewhere). We explain the concept of return on capital further in section III. The AER Guideline requires that pipeline service providers disclose the sources, methods and assumptions used to estimate the rate of return on capital. However, pipeline service providers are not required to disclose the rate of return itself. We report in section IV.B the rates of return that we were able to calculate from the published information.

32 AER Guideline, pp. 19–20.

(b) unless inconsistent with paragraph (a), the value of any assets used in the provision of the pipeline service is to be calculated as:

(i) the cost of construction of the pipeline […];
plus:
(ii) the amount of capital expenditure since the commissioning of the pipeline;
less:
(iii) the return of capital recovered since the commissioning of the pipeline; and
(iv) the value of pipeline assets disposed of since the commissioning of the pipeline.

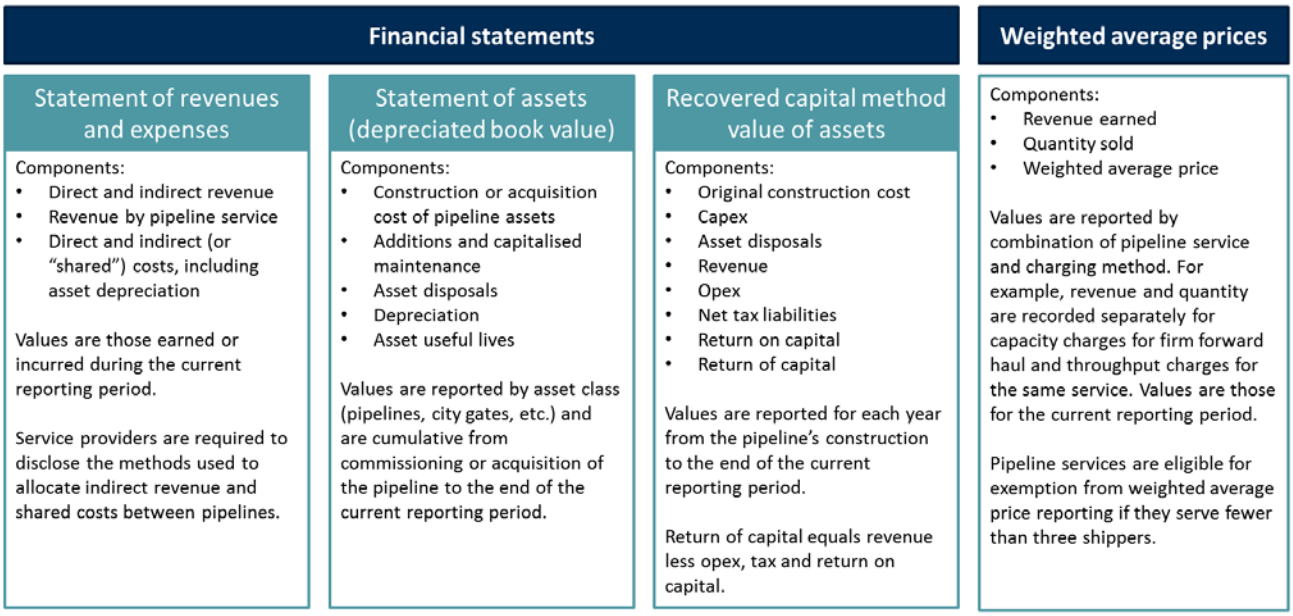
24. Rule 569(3)(a) sets out a pricing principle to which an arbitrator of an access dispute must have regard: that "the price for access to a pipeline service on a non-scheme pipeline should reflect the cost of providing that service, including a commercial rate of return that is commensurate with the prevailing conditions in the market for funds and reflects the risks the service provider faces in providing the pipeline service.". Furthermore, Rule 569(4) provides that the access price should reflect an asset value based on construction cost less capital already recovered, unless using this valuation method would be inconsistent with the objective of Part 23 (prices that reflect the outcomes of a workably competitive market).

25. The AER states that "[t]he RCM asset valuation is intended to align with the building block approach applied to regulated pipelines, in situations where the regulated pipeline was constructed after the regulatory framework for gas pipelines came into effect (ie, post November 1997). However, the AER recognises that there may be circumstances where this approach is inconsistent with the workably competitive market objective set out in rule 546(1) of the NGR [ie, the objective of Part 23], and the asset value could be different to that derived using the RCM. Therefore, the book value is also required to be published to provide an alternative measure for comparison".[33]

26. Figure 1 summarizes the information that service providers are required to disclose as set out in the AER Template.

[33] AER Explanatory Statement, pp. 4–5.

Figure 1
Overview of the AER financial reporting template



Note: The AER Template includes fields to (i) report pipeline information, such as its location, length, number of customers, and services provided and (ii) to report the pipeline's return on assets over the reporting period, calculated as earnings before interest and tax divided by total asset value under the depreciated book value method. There is also a worksheet to record any amendments the service provider makes to the template.

27. The AER Guideline also requires service providers to supplement their financial reporting with a "basis of preparation" document.[34] The basis of preparation (BoP) provides additional information on the sources, methods and assumptions used to produce each of the components in Figure 1.[35] The AER states that the BoP is meant to (i) "[e]nable an understanding of how the amounts reported in the pipeline financial statements are determined or calculated", (ii) "[a]ssist with interpretation of information reported in the pipeline financial statements", (iii) "[a]ssist with comparison of information provided in the pipeline financial statements to the service provider as a whole", and (iv) "[p]rovide an understanding of how shared amounts are allocated".[36]

[34] AER Explanatory Statement, p. 12.

[35] AER Explanatory Statement, p. 2.

[36] AER Explanatory Statement, p. 12.

III. Framework for using Part 23 information to calculate access pricing benchmarks

28. In this section, we outline the economic principles that we consider relevant for determining access prices. We rely on these principles in our calculations of pricing benchmarks for the Part 23 pipelines we analyse in this report.

29. This report focuses on how benchmarks relevant for assessing a "reasonable price" for pipeline access might be derived from the Part 23 financial information, where a reasonable price is one that, "so far as practical, reflect[s] the outcomes of a workably competitive market".[37] We discuss our understanding of the concept "workably competitive market" in subsection A. In subsections B and C we outline different approaches for calculating benchmark prices, and explain the circumstances in which each may be more or less relevant.

A. A workably competitive market

30. The concept of a "workably competitive market" has a long history.[38] The concept implies something different from the "textbook" definition of perfect competition, where there is a single "market price" equal to marginal cost.[39] A workably competitive market is one in which, even if competition is not perfect, it may not be possible to improve outcomes by regulating prices.[40]

31. We think that the following outcomes are consistent with a workably competitive market.

- Willing buyers and willing sellers are able to negotiate access agreements which create economic value. This implies that the cost of using a pipeline does not exceed the benefit

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37 National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 546(1).

38 For example, Productivity Commission, "Review of the Gas Access Regime", Inquiry Report No. 31, June 2004, p. 254, in citing J.M. Clark, "Toward a Concept of Workable Competition", *The American Economic Review*, 30(2), 1940: 241–256. See also GMRG, "Gas pipeline information disclosure and arbitration framework – Final Recommendation", June 2017, p. 20.

39 For a discussion on the concept of workably competitive market versus perfect competition, see R. Shogren, "Dynamic Efficiencies and Workable/Effective Competition – Comments on a Paper by William G. Shepherd", Australian Competition and Consumer Commission 2004 Regulatory Conference, Gold Coast, Australia, 29 July 2004, pp. 2–3. Mr Shogren's discussion begins with the interpretation of the terms "competition" by the Supreme Court in connection with a dispute between Epic Energy and the Gas Access Regulator in Western Australia regarding prices for third-party access to the Dampier to Bunbury Natural Gas Pipeline. See *Re Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231.

40 A.B. Delp & J.W. Mayo, "The evolution of "competition": Lessons for 21st century telecommunications policy", *Review of Industrial Organization*, 50(4), 2017: 393–416, p. 401, in citing J.W. Markham, "An alternative approach to the concept of workable competition", *The American Economic Review*, 40(3), 1950: 349–361.

generated from using it, and therefore that the cost of using a pipeline is less than the cost of available alternatives.

- The economic value created by an access agreement is shared between the shipper and the pipeline service provider. However, the sharing of economic value between a shipper and a service provider may not be equal.
  - When capacity is scarce and shippers have to compete with each other to access a pipeline, prices are likely to be high (and shippers with relatively higher willingness to pay are more likely to obtain access). Thus, where capacity is scarce, shippers receive less of the economic value available to be shared (and the pipeline receives more). Correspondingly, actual returns on existing pipeline investment will be higher when capacity is scarce, all else equal.
  - When capacity is plentiful, pipeline service providers are more likely to offer services to shippers with lower willingness to pay (ie, pipeline owners are more likely to charge lower prices). Correspondingly, actual returns on existing pipeline investment will be lower when there is spare capacity, all else equal.
  - The sharing of economic value between shippers and pipeline service providers can vary from one agreement to another, even for similar services, including on the same pipeline. Thus, prices for similar services will not necessarily be the same (ie, there can be price discrimination), particularly if there are infrequent transactions.[41]
- Anticipated returns on new investment opportunities can be low when new investment is not needed (ie, when there is excess pipeline capacity). Further, anticipated returns from new investment opportunities will not persist above a rate of return commensurate with the risk of providing pipeline services.[42] The threat of entry should constrain the ability of pipeline service providers to charge prices that generate a rate of return persistently above a normal commercial rate.[43]
- Actual returns on existing investment can be high or low, depending on market circumstances and how circumstances evolve over time. Unanticipated changes, such as new sources of gas supply, can result in actual returns being above or below normal commercial rates of return.
- Pipeline service providers cannot sustain prices above the total cost of providing the service, where the total cost is that associated with operating new assets. Shippers will not be able to obtain access at prices below the incremental cost of providing the service.

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41 See, for example, J. Tirole, "Price Discrimination" in *The Theory of Industrial Organization* (Cambridge, MA: MIT, 1988), pp. 133–168.

42 S. C. Myers, "The Application of Finance Theory to Public Utility Rate Cases", *Bell Journal of Economics and Management Science*, 3(2), 1972: 58–97.

43 H. Demsetz, "Why Regulate Utilities?", *Journal of Law and Economics*, 11(1), 1968: 55–65.

32. In concluding that there was evidence of pipeline service providers engaging in monopoly pricing, the ACCC compared "the rates of return some pipeline operators have assumed when determining the price of access to the incremental investments that have occurred in the last three years" to "the benchmark return on equity the Australian Energy Regulator (AER) has estimated in gas regulatory decisions over this period".[44] As explained above, in a workably competitive market, the threat of entry should constrain the ability of pipelines to generate excess returns above the level of returns commensurate with the risk of providing pipeline services. However, the latter may be difficult to estimate. A "benchmark" rate of return (such as that estimated by the AER) can serve as a useful starting point.[45] However, there may be important differences between the risks faced by pipelines operating commercially in a competitive market and those faced by pipelines operating under full price regulation, particularly if the latter are not significantly exposed to competition. For example, distribution pipelines with natural monopoly characteristics are regulated so that prices provide capital recovery and a benchmark rate of return, if operated efficiently. In contrast, the recovery of, and earning a rate of return on, investment is not guaranteed for a pipeline in a competitive setting. A pipeline may be exposed to significantly higher risks of asset stranding, for example due to unexpected changes in gas production or gas demand, or competitive entry, than a distribution pipeline with natural monopoly characteristics. These risk differences derive from the nature of the market in which the pipeline provides services, but may also be influenced to a degree by the way in which the pipelines are regulated, including whether they are regulated.

33. Where providing access creates economic value, the value of the access to the shipper must be greater than the cost to the pipeline of providing access. An access price greater than the pipeline's cost and less than the shipper's value results in the economic value of providing pipeline access being shared between shipper and pipeline. Therefore, relevant pricing benchmarks include both benchmarks that relate to the value of capacity to shippers, and benchmarks that relate to the cost to pipelines of providing capacity. We discuss these pricing benchmarks in the next two subsections.

B. Value of capacity

34. Shippers pay for pipeline capacity because they are able to create economic value from it: they may be moving gas from a location with plentiful supply to one where there is plentiful demand, or they may be using the gas to generate electricity or in some other industrial process. Pipeline capacity is valuable to shippers where it is cheaper than an alternative that the shipper would otherwise have to use. For example, a shipper selling gas to customers downstream might be able to use a different pipeline; a shipper wanting to develop a new gas field might have a choice of pipelines or might be able to use the gas locally for power

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[44] ACCC, "Inquiry into the east coast gas market", April 2016, p. 8.

[45] For example, the AER sets out a rate of return instrument, which uses the same methodology to calculate the rate of return on capital to all regulated services and service providers (including gas and electricity distribution and transmission networks). See AER, "Rate of return instrument", December 2018.

generation; and a shipper with a new remote mining project might have the choice between gas, diesel or electricity from the transmission grid. In these examples, the value of the pipeline capacity is in the avoided cost of alternatives.

35. The value of pipeline capacity to an individual shipper will depend on that shipper's individual circumstances, the use to which the capacity would be put, and the alternatives potentially available to that shipper.

36. In some circumstances, the shipper may have no alternative other than building its own pipeline, or abandoning the project that would require the use of the pipeline.

37. In circumstances where not all potential shippers will be able to use a pipeline due to a capacity constraint, and where expansion is not viable, the efficient outcome will be for only the shippers with the highest valuation to obtain access (including, potentially, by trading with each other in the secondary market).

38. This report focuses on Part 23 financial disclosures and how that information might be useful for setting a reasonable access price. We have not created benchmarks based on the value of capacity to shippers because such benchmarks would require information about the circumstances of shippers. Such information is not part of Part 23 financial information disclosure, and could be very different for different shippers on the same pipeline, as well as for different pipelines. Nonetheless, benchmarks based on value may be relevant for determining a reasonable access price. In section III.C.4 below we discuss the circumstances in which a value-based benchmark may be more relevant than one based on the cost to the pipeline of providing capacity.

C. Cost of capacity

39. Cost-based pricing benchmarks are based on the cost of producing the goods or services.

40. Unlike value-based pricing, the information required for cost-based pricing is available from service providers, which are likely to have accurate information on their own costs of producing goods or services. However, cost-based pricing does not take into account factors such as prices charged by competitors, and willingness to pay or level of demand, all of which are relevant for price formation in workably-competitive markets. Cost-based pricing is not forward-looking (for example, prices based on cost do not signal the need for expansion of pipeline assets) nor does it provide incentives for service providers to be efficient.

41. If a cost-based benchmark includes a return of and on assets valued at depreciated historical construction cost, the cost-based benchmark could be very different from a value-based benchmark. However, if assets are valued in some other way, the cost-based benchmark and a value-based benchmark could be similar. Assets valued at replacement cost rather than depreciated historical cost would give very different benchmark prices.

42. In considering benchmarks based on the cost of providing pipeline services, it is helpful to distinguish three components of total cost: incremental (or avoidable) cost; fixed operating cost; and investment cost (ie, a return of and on the value of existing assets, taking into

account the impact of income tax). All three are potentially components of a cost-based pricing benchmark. We explain the three cost components below.

1. Incremental cost

43. Incremental cost is the additional cost associated with providing an additional unit of service and would not be incurred (ie, is an avoidable cost) if the additional unit of access were not provided. For example, transporting an additional unit of gas may require additional compressor usage (fuel, and perhaps maintenance), and providing an additional unit of capacity may require investment in additional compressors.

44. One benchmark of cost-based pricing is incremental cost, ie, shippers pay for the additional cost incurred when moving a unit of gas. In a workably competitive market, access should not be provided at prices below the incremental cost of providing the service.[46] Pricing at incremental cost is economically efficient in the short run (the time period over which new investment to expand the network is not required): any unit of gas that can profitably be moved would be moved. Pricing below incremental cost is not profitable for the provider as it costs the provider more to provide the additional unit of the service than the price it receives for it. From a social welfare perspective, pricing below incremental cost is not optimal since shippers value the service less than the cost of providing it.

45. Note that if there is no capacity constraint, and assuming that the avoidable costs of compressor usage are covered by the usage charge,[47] the avoidable cost of providing access to one customer is zero.

2. Fixed operating costs

46. The provision of pipeline services also entails certain fixed operating costs, ie, costs that would not be incurred if the pipeline were not in operation. Fixed operating costs do not vary with the amount of pipeline service provided, and are therefore unavoidable unless the pipeline shuts down completely. Examples of fixed costs include routine maintenance and repair cost.

47. Fixed costs do not vary as usage of the pipeline increases or decreases. However, incurring fixed costs is necessary for the operation of pipeline assets, and pipeline owners expect to recover fixed costs when committing to provide pipeline services. As a result, shippers would commonly expect to make a contribution to fixed operating costs. However, the contributions may be unequal (for example, on the basis of AUD per unit of Maximum Daily Quantity (MDQ)). There may be a variety of ways to determine each shipper's appropriate contribution to fixed costs.

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[46] D. Biggar, "Access pricing and competition", prepared for the ACCC conference on Regulation and Investment, 2001, pp. 1–2.

[47] Gas pipelines commonly recover the costs of compressor fuel "in kind" or in a usage charge separate from the reservation charge.

48. Since fixed costs do not vary with the incremental usage of the pipeline, it is more efficient to recover fixed costs in a fixed reservation charge rather than a variable usage charge (for example, per unit of MDQ rather than per unit of gas transported). A reservation charge to recover fixed costs is more efficient than a usage charge because if the usage charge is increased to recover fixed costs, some volumes that might otherwise be transported might not be transported at all.[48] In addition, a usage charge might lead to an over- or under-recovery of fixed costs as volumes vary.

49. From the perspective of economic efficiency, it is better to recover fixed costs in inverse proportion to the sensitivity of each user's demand to changes in price.[49] This factor is termed the user's "price elasticity of demand".[50] When shippers pay prices to contribute to fixed cost recovery and prices are in inverse proportion to the shippers' price elasticities of demand, a more price-sensitive shippers makes a smaller contribution to fixed cost recovery than does a less price-sensitive shipper. This pricing structure thereby minimizes the impact of fixed cost recovery on overall demand.

50. In the absence of information on shippers' price elasticity of demand, fixed cost recovery requires an alternative method to allocate fixed cost across the different shippers' of a pipeline. For example, fixed costs might be allocated based on contracted quantity of MDQ, or the length of the pipeline over which gas is transported.[51] This means a user with a smaller contract or who transports gas over a small section of the pipeline will contribute less to fixed cost recovery than a user with a larger contract or who transports gas the entire length of the pipeline.

51. The recovery of fixed costs is necessary to permit pipeline service providers a reasonable opportunity to earn a fair return on their investment. However, in some circumstances the opportunity cost of providing access to one customer may be zero, and therefore it might not be efficient to increase the access price to recover fixed costs.

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48 D. Biggar, "Access pricing and competition", prepared for the ACCC conference on Regulation and Investment, March 2001, p. 14.

49 D. Biggar, "Access pricing and competition", prepared for the ACCC conference on Regulation and Investment, March 2001, pp. 10–11.

50 A. Marshall, *Principles of Economics*, London: MacMillan and Co., 1895), p. 178.

51 For example, APA states that the standard access terms for the Goldfields Gas Pipeline include a three-part tariff: a toll charge applied to the GJ of MDQ that a shipper reserves per day; a capacity reservation charge applied to the GJ of MDQ per day multiplied by the distance (in kilometres) from injection point to receipt point; and a throughput charge per GJ per kilometre. See APA, *Current tariffs and terms*, July 2018.

3. Investment cost

a. Economic principles related to investment cost

52. Pipeline service providers also incur the cost of constructing or acquiring pipeline assets. From an economic perspective, once costs are sunk they should not affect future decisions. Therefore, in a commercial setting, sunk costs are irrelevant. Sunk costs are also irrelevant if the only consideration is short-run efficiency, for example if there is excess capacity and no prospect of the need to expand capacity in the future.

53. However, an environment in which access is expected to be priced at incremental cost plus fixed operating cost is not conducive to attracting investment in new capacity. If a service provider anticipated that it will not be able to recover its capital investment in pipeline construction, it would not enter the market and make the investment in the first place. Where the service provider has made an investment in order to provide a service, in the absence of a contract or an appropriate regulatory framework, shippers would have an incentive to promise a high price before the investment is made, and a low price afterwards.

54. The same can also be said for the customer's investment. For example, a service provider might promise its shippers a low access price before the shippers make an investment that will rely on the use of the pipeline assets. Once the shippers have made the investment, the pipeline service provider has an incentive to charge a higher price.[52]

55. Regulation or efficient use of long-term contracts can protect against strategic bargaining from both pipeline service providers and shippers.[53] In practice, many systems of access price regulation are designed to permit the pipeline service providers to expect to earn a normal return on investment. In such a regulatory framework, expected revenue over the life of the asset must be equal to total cost (including an appropriate return of and on invested capital). A similar outcome can occur when shippers enter long-term contracts for the use of infrastructure. The contracts provide shippers with assured access and the infrastructure owner with an assured return on investment (subject to performance and operating risk). The contracts protect the pipeline service providers and shippers from the risk of strategic bargaining that could otherwise expropriate the value of sunk investments.

56. In sum, in the interest of maintaining an environment that is conducive to attracting long-term investment in new capacity when needed, it is necessary to consider the recovery of and return on investment in setting prices. This is particularly the case where access pricing is a "repeated game" – ie, the experience of one pricing decision (even if investment is not required to meet the access request) may influence willingness to invest to meet a future access request.

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[52] D. Biggar, "Is protecting sunk investments by consumers a key rationale for natural monopoly regulation?", *Review of Network Economics*, 8(2), 2009: 128–152, p. 129.

[53] D. Biggar, "Is protecting sunk investments by consumers a key rationale for natural monopoly regulation?", *Review of Network* Economics, 8(2), 2009: 128–152, pp. 145–146.

57. Depending on the circumstances, there are different methods to estimate the value of assets on which the return of and on investment are calculated.

b. Asset valuation methods

58. Broadly speaking there are three approaches to asset valuation for the purpose of setting an access price: historical cost, replacement cost, and market value. Each approach can give rise to a different asset value on which the return of and on capital can be calculated.

59. "Historical" or "original" cost means that the value of the asset is measured with reference to the original expenditures incurred when the asset was first constructed, adjusted for depreciation (ie, return of capital) over time. Historical cost relies on accounting books and does not require any assumptions about future market value or demand for access, and therefore is a relatively straightforward starting point for asset valuation. However, asset valuation based on historical cost is not forward looking. From an economic perspective, historical cost is sunk and should not affect the decisions of pipeline service providers to invest or the price at which to provide access. However, to attract investment, it is necessary to ensure that pipeline investors have an expectation that they can recover and earn a reasonable rate of return on their investment.

60. Replacement cost estimates the cost of reproducing the existing assets at the current cost of construction, either with or without "optimization" to current usage patterns and technology. Optimised replacement cost (ORC) more closely models the costs faced by a new entrant in the market.[54] Another variation of replacement cost is "depreciated optimized replacement cost" (DORC). DORC accounts for the age of the existing asset, but is based on the optimized cost of constructing a new asset.

61. An asset value based on replacement cost is forward looking and can be used to encourage new investment. Access prices based on replacement cost include a capital charge that relates to the investment associated with new infrastructure, rather than a capital charge intended to recover the investment actually made in the past. It can be complex and subjective to estimates of asset values under replacement cost methodologies.

62. The value of pipeline assets can also be estimated by analysing the value of services provided by the asset now and in the future, ie, the "market value" of the services provided (and, hence, the market value of the asset). Sometimes, a market value of the infrastructure asset can be observed if the asset has been sold (and the price was made public) or privatized. However, there is a degree of circularity in using the sale price of an asset to determine the access price since the sale value was presumably determined by the buyer's expectations of future access prices.

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[54] P.R. Carpenter and Carlos Lapuerta, "Asset Valuation and the Pricing of Monopoly Infrastructure Services: A Discussion Paper," 28 July 2000, pp. 8–9.

63. In summary:

- valuation based on historical costs has the advantage of compensating investors for the capital committed to the asset, but has the disadvantage that the resulting prices may have no connection either with the current value of service in the market or the long-run cost of replacing or expanding capacity;
- valuation based on replacement costs may provide better signals of the long-run cost and therefore assist with determining whether an asset should be expanded and can facilitate competition between alternative technologies, but it does not provide investors with a normal rate of return on their existing investments (except by accident); and
- valuation based on transaction prices for assets is forward-looking (like replacement cost) and is based on actual prices rather than judgment, but it is potentially circular and does not address market power concerns.

c. Return of capital

64. If an initial asset value is available, the asset value in subsequent years can be calculated by applying a depreciation method. There are different depreciation methods and the choice of one over another can have a significant impact on the current asset value at a given point in time. For example, under straight-line depreciation, the initial asset value is assumed to decline by the same amount (either in real terms or nominal terms) every year over the expected life of the asset. A levelised depreciation method sets depreciation such that the service provider can recover its investment and earn a return on investment from a constant payment each year (either in real terms or nominal terms) over the expected life of the asset. The levelised approach is similar to a residential mortgage, whereby the borrower pays off the principal amount plus interest through equal payments over the term of the mortgage.

65. Two pipeline service providers with the same initial asset value and the same objective of setting access prices based on total cost can arrive at significantly different profiles of asset value, and hence access prices, over time if they choose different depreciation methods. Either or both could be consistent with a workably competitive market.

66. Part 23 requires service providers to report the depreciated book value of assets and an asset value based on the RCM. Under both methods, the starting point is the original investment (however, the depreciated book value allows pipeline owners to use acquisition cost, as opposed to original construction cost, if the pipelines were acquired). Under the depreciated book value method, depreciation is calculated based on a straight-line method. Under the RCM, depreciation is the residual value once operating expenses and an assumed return on capital (and taxes) are netted from revenues. As a result, under the RCM, if a pipeline is successful in reducing operating costs, this will flow through into higher returns of capital and therefore a lower future asset value. Equally, if the pipeline is underutilized and revenues are low, this will flow through into lower returns of capital under the RCM and therefore a higher future asset value. A cost-based pricing benchmark using the RCM therefore incorporates these risks and would pass them on to future shippers. Further, under the RCM, if a service provider acquires the pipeline, the revenue from contracts obtained at the time

of the acquisition is used to "depreciate" the construction cost, which does not include any capitalised premium value of these same contracts.

d. Rate of return on capital

67. Capital, like other productive resources, is limited and therefore has an opportunity cost. Since the supply of capital is limited, in order to make an investment, investors must forgo the opportunity to invest elsewhere. Capital is therefore costly to acquire just like any other input of production.

68. The return on capital compensates investors for the opportunity cost of the capital invested, ie, what could be earned elsewhere by making an investment of comparable risk. This rate of return is typically referred to as the cost of capital. The cost of capital is set in the market by the returns from alternative, comparable-risk investment opportunities. The cost of capital represents the minimum return investors require to finance specific investments, or in other words, the cost to the firm to attract that capital away from competing investments.

69. In setting out the pricing principles that an arbitrator must consider when making an access determination, Part 23 states that "the price for access to a pipeline service on a non-scheme pipeline should reflect the cost of providing that service, including a commercial rate of return that is commensurate with the prevailing conditions in the market for funds and reflects the risks the service provider faces in providing the pipeline service".[55]

70. The rate of return on capital that equity investors receive is net of income tax paid at the corporate level, noting that in Australia corporations are able to provide equity investors with "franking credits", which represent corporate income tax paid and have value to investors who pay income tax. Thus the rate of pre-tax return that a service provider is expected to achieve has to be greater than the rate of return investors expect to receive (given the "prevailing conditions in the market for funds" and "the risks the service provider faces in providing the pipeline services"),[56] because the service provider will pay income tax. If a post-tax rate of return is used to estimate the return on capital component, a separate tax cost component needs to be added to the total cost of providing pipeline services.

4. Other considerations

71. Overall, short-run efficiency means access should be priced at levels that reflect incremental cost. Long-run efficiency, however, requires prices at levels above incremental cost to allow the pipeline service providers to also recover fixed and sunk costs. An access price that provides a return of *actual* investment and a reasonable rate of return on that investment should be sufficient for the purpose of incentivising investment in the pipeline assets. However, an increase above the level that provides a normal rate of return on actual investment can be appropriate in certain circumstances.

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55 National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 569(3.a).

56 National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 569(3.a).

72. In particular, if the demand for pipeline services exceeds the capacity of the pipeline, the price would need to rise such that only shippers with the highest willingness to pay (ie, shippers that derive the highest value from obtaining access) would be given access. High prices due to excess demand also serve as a signal for pipeline expansion.

73. If there is no excess demand, but the access price is nevertheless set above the level required to provide a return of and on invested capital, the result can be sub-optimal use of the asset, and upstream and/or downstream inefficiencies.

74. Sharing of economic value between pipeline service providers and shippers can have an impact on future investment in pipeline capacity as well as investment in upstream and downstream activities, because there will be multiple transactions between pipeline owners and shippers over time. A greater share of economic value received by pipeline service providers (ie, higher access prices) reduces the price of gas received by gas producers, which in turn could lead to lower investment in gas production and exploration. Equally, low returns on capital invested in pipelines due to low access prices will tend to reduce incentives for investment in new capacity. An efficient sharing arrangement is one that incentivises investment where it is most valuable (that is, not only investment in pipeline capacity but investment in the upstream and downstream industries also needs to be encouraged).

75. In sum, a framework for determining pipeline access prices requires an understanding of (i) the incremental cost of providing an additional unit of pipeline service, (ii) the fixed costs of operating the pipeline assets, (iii) the capital investment required and the corresponding expected rate of return on capital, and (iv) other characteristics of the shippers and pipeline assets (eg, whether or not the pipeline is capacity constrained).

IV. Overview of the Part 23 information disclosed by service providers

76. The AER Guideline requires that service providers follow a template provided by the AER to report the Part 23 financial information. While the AER Template details the items that the AER expects service providers to disclose, different service providers might rely on different sources, methods of estimation or assumptions in producing the financial information.

77. Service providers are required to submit a BoP for each non-scheme pipeline to provide additional information on the sources, methods and assumptions the service providers used to produce the Part 23 financial information.[57] The AER states that the BoP must be used to (i) "explain the source/s from which the service provider obtained the information

[57] AER Explanatory Statement, pp. 2–3.

provided",[58] (ii) "explain the methodology the service provider applied to provide the required information, including any assumptions the service provider made and inputs used",[59] including the method used to allocate shared supporting assets between non-scheme pipelines and other operations,[60] and (iii) justify why estimates are used in place of "actual information".[61]

78. In this section we first summarise our review of the BoP and highlight the differences in the assumptions and methods used by different service providers when completing the AER Template. We then provide a summary of our review of the reported financial information. In our review, we have not assessed whether service providers are complying with their obligations to disclose information under Part 23, nor have we assessed whether disclosures are compatible with the AER Guideline or any other applicable standards. Our focus is on whether the disclosed information would be useful to prospective shippers seeking to negotiate access to a pipeline, and whether it would be useful in an arbitration of an access dispute. Our analysis of the reported information (i) provides a set of summary statistics that compare the same information across pipelines (for example, shared costs as a percentage of total costs, or the rate of return on capital) and (ii) highlights any inconsistencies in the assumptions used across service providers, and in some cases, inconsistencies between what a service provider discloses in its BoP and reports in the Template.

A. The basis of preparation statements

79. In summary, our review of the BoP submitted by the different service providers shows that:

    a. In some cases, the reported information is not based on costs actually incurred by service providers or revenues actually received, but is instead estimated figures. Sometimes this is because the necessary records are not available, but in other cases it is because service providers implement certain adjustments. For example, APA's reported operating expenses is "inclusive of adjustments so that those costs are to be equivalent to those of a firm operating a business of size and complexity of the non-scheme pipeline in the context of a workably competitive market".[62]

    b. Service providers that own multiple pipelines use different allocation methods to allocate total shared revenues and total shared expenses across individual pipelines.

    c. The inputs and assumptions underlying the calculation of the recovered capital method vary across service providers.

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58 AER Guideline, p. 26.

59 AER Guideline, p. 26.

60 AER Guideline, p. 12.

61 AER Guideline, p. 26.

62 APA Basis of Preparation, p. 14.

d. While the AER Template lists the individual expense and revenue components that service providers can use in their information reporting, it also allows for "catch-all" fields (such as "other direct revenue", "other direct cost", or "other shared cost"). Some service providers use these fields to report certain cost components that are not mentioned by the AER Guideline and other service providers.

e. APA states that for the Moomba to Sydney Pipeline, the reported Part 23 information relates to more than just the parts of the pipelines subject to Part 23 reporting.[63] In the case of the Moomba to Sydney Pipeline, the financial information reported includes covered segments of the pipeline system.

80. We expand on each of these points in the sub-sections that follow.

1. Estimated versus actual information

81. Service providers are required to report historical financial information, including capital expenditure, revenue and expenses within the framework of the RCM. More recent revenue and expenses (e.g., revenue and expenses for the most recent reporting period) appear to be actual information coming from the service providers' regular internal accounting systems (referred to by service providers as financial reporting systems or management reports) and accounting records such as invoices, records of purchase orders, or timesheets.[64] However, for some pipelines, historical information in earlier years was estimated, rather than actual. Examples include the Moomba to Adelaide Pipeline (MAPS, owned by EPIC) and APA pipelines.

82. In the case of APA pipelines, APA states that some operating costs are incurred at a divisional or corporate level, rather than by individual service provider entities. APA allocates these operating costs in "the context of delivering outcomes consistent with a workably competitive market. The reported operating expenses is inclusive of adjustments so that those costs are to be equivalent to those of a firm operating a business of size and complexity of the non-scheme pipeline in the context of a workably competitive market".[65] APA states that this "[r]eplicates a standalone firm with a single asset operating in a workably competitive market".[66] In addition, the reported revenue for Goldfields Gas Pipeline is estimated rather than actual due to the lack of historical information.[67]

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63 APA Basis of Preparation, pp. 2–4.

64 See for example: APA Basis of Preparation, pp. 9, 20; EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 16; Jemena Basis of Preparation – Darling Downs Pipeline, p. 4.

65 APA Basis of Preparation, p. 14.

66 APA Basis of Preparation, p. 6.

67 "While the operator has access to all relevant information on capital and operating expenses in respect of the uncovered capacity, it has no information regarding the revenues earned by all of the joint venturers or on the tax position of the joint venturers. The operator requested revenue information

83. In the case of MAPS, the source of revenue and expense information varies through time. For the period when MAPS was regulated, the reported revenue and expenses seem to be the allowed figures (based on the ACCC's determination), rather than actual recorded amounts. The different sources of revenue and expenses EPIC uses are as follows:

    a. For the period prior to 2005, revenue and expenses are estimated using the ACCC's determination. These presumably are the revenue and expenses that MAPS was authorised to collect. However, the ACCC determination indicates that EPIC could earn additional revenue from the sale of non-reference services.[68] Further, EPIC could also have incurred more or less expenses than anticipated in the ACCC's decision.

    b. For 2006 through 2017, revenue and expenses are estimated using historic management reports. EPIC owns two pipelines, the Moomba to Adelaide Pipeline System (MAPS) and the South East Pipeline System (SEPS). Part 23 only applies to MAPS. Therefore, for this period, EPIC makes adjustment to remove revenue and expenses associated with the SEPS.[69]

    c. 2018 onwards: For the most recent revenue, EPIC states that all its GTAs relate to either MAPS or SEPS, which suggests no adjustment to exclude SEPS is required.[70] With regard to expenses, EPIC allocates shared costs between MAPS and SEPS in proportion to the pipelines' capacity.[71]

2. Shared versus direct

84. The AER Guideline requires that service providers categorise costs into "direct costs" and "shared costs"[72] and assets into "pipeline assets" and "shared supporting assets".[73] There is no definition of "shared costs", other than "[s]ervice providers are required to allocate only a fair proportion of shared costs such as corporate overheads to each pipeline" and a list of different

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from the joint venturers. While this information was able to be provided by the Southern Cross companies, it was not able to be provided by Alinta for periods prior to 1 January 2018. In the preparation of the financial information under this Guideline, the operator has estimated the historical revenue earned by Alinta from the provision of pipeline services using the uncovered capacity for the purposes of the Recovered Capital Method asset valuation. This estimate was based on the amount of uncovered capacity attributable to Alinta over the relevant period and an estimate of prevailing gas transportation tariffs in the market at the relevant time. While this estimate is unlikely to be precisely accurate, any inaccuracy is unlikely to have any material impact on the Recovered Capital Method asset value as at 30 June 2018." APA Basis of Preparation, p. 4.

68 ACCC AA proposed by Epic Energy for the MAPS - Final Decision, September 2001, p. 61.

69 EPIC Basis of Preparation – Moomba to Adelaide Pipelines System, p. 16.

70 EPIC Basis of Preparation – Moomba to Adelaide Pipelines System, p. 7.

71 EPIC Basis of Preparation – Moomba to Adelaide Pipelines System, p. 9.

72 AER Guideline, p. 9.

73 AER Guideline, p. 11.

shared cost categories, such as "[s]hared [e]mployee costs", "[i]nformation technology and communication costs", and "[i]ndirect operating expenses".[74] The AER defines "shared supporting assets" as "assets used to support the operation of multiple pipelines and/or other revenue generating activities other than just the pipeline.". The AER also requires that "[w]here an asset is used to support the operation of multiple pipelines or other revenue generating activities an apportionment of the asset is required".[75] In addition, service providers are also required to categorise revenue into direct revenue (ie, "revenue directly earned by the pipeline") and indirect revenue ("revenue that does not directly relate to a specific pipeline").[76]

85. The AER Guideline requires that the service providers disclose in the BoP for indirect revenue, shared costs and shared assets: (i) the allocators used, (ii) an explanation of why such allocates are used, and (iii) "the numeric quantity or percentage of the allocator to be applied for each cost item [or each revenue item, or each asset or liability], including an explanation of how the numeric quantity or percentage has been calculated".[77]

86. Our review of the BoP shows that (i) not all service providers disclose the exact percentage or numeric quantity of the allocator (for example, Jemena and APA) and (ii) certain service providers include certain cost components under shared and direct costs which are not mentioned by other service providers and the AER Guideline. For example, EPIC and APA note the inclusion/exclusion of different cost components.

    a. APA includes in its direct costs "directly attributable" and "other attributable" costs. The latter are "costs not directly attributable to the assets but incurred by APA's Transmission division".[78] Examples of these costs are (i) APA's Integrated Operations Centre (IOC) which manages APA's non-scheme and regulated pipelines throughout Australia, (ii) national cost centres that provide transmission services such as invoicing and billing, (iii) costs surrounding health, safety and environment services, and (iv) human resources training and development. APA allocates these "other attributable costs" across the pipelines based on time/effort, number of customers, state based, or

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74 AER Guideline, pp. 9-10.

75 AER Guideline, p. 4.

76 AER Guideline, p. 15.

77 AER Guideline, pp. 15-16.

78 The Transmission Division is responsible for the management of APA Group's transmission and gas storage assets, including all aspects of commercial and operational performance. APA states that "In order to give a true reflection of the cost of running an asset, it is necessary to allocate APA's Transmission costs to the asset. APA's Transmission costs are reviewed periodically to determine the extent to which the business unit's function has a bearing on the assets. Examples of such costs include the allocation of APA's Integrated Operations Centre (IOC) which manages APA's non-scheme and regulated pipelines throughout Australia." APA Basis of Preparation, p. 9.

number of overall headcount. These costs seem to be shared costs but APA reports them under direct cost.

b. APA uses the category "other direct costs" to report "adjustments" so that its operating expenses are "equivalent to those of a firm operating a business of a size and complexity of the non-scheme pipeline in the context of a workably competitive market".[79] Note that "other direct costs" for APA pipelines can be as high as more than 80% of total cost (see Table 20 in section IV.B.3).

c. EPIC includes costs such as consultants, audit and legal advice, insurance and travel expenses in shared costs.[80] Shared costs make up almost 80% of the Moomba to Adelaide Pipeline System's total costs (see Table 18 in section IV.B.3)

87. In addition, SEA Gas not only allocates shared costs but also allocates direct costs between its two pipelines, Port Campbell to Adelaide Pipeline and Port Campbell to Iona Pipeline. SEA Gas explains that "[e]xpenses that were considered to be of a nature that have a direct impact on the pipeline assets, were categorised as a direct cost. Expenses that were considered to be general in nature, but are required in order to ensure operation of the pipeline, were categorised as indirect. All expenses have been allocated over the two (2) pipelines".[81]

3. Allocation methods for shared assets, expenses and revenue

88. Service providers that own multiple pipelines have to allocate assets, expenses and revenue to individual pipelines. The allocation method is different across different service providers.

89. EPIC, SEA Gas and Jemena allocate shared costs and assets using different cost allocators. Examples of the different allocation methods include:

a. EPIC allocates shared costs across pipelines in proportion to the ratio of capacity of pipelines (except for motor vehicle depreciation, which is allocated based on time charged to the MAPS for maintenance activities). SEA Gas allocates shared costs across pipelines in proportion to either pipeline revenue or length of pipelines. Jemena sources information from SAP using a combination of project and cost elements. It allocates shared cost either directly to the asset through a PM Order, or based on

[79] APA Basis of Preparation, p. 9.

[80] EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 10.

[81] SEA Gas Basis of Preparation, p. 4.

allocation methodologies such as historic time-writing data, or based on causal drivers (e.g., number of laptops users for IT Telecommunication costs).[82,83]

b. EPIC and SEA Gas allocate shared property, plant and equipment across different pipelines using different allocators such as time charged, capacity of pipelines or the length of the pipelines. For example, EPIC allocated motor vehicle depreciation based on "the time charged to the MAPS for maintenance activities relative to the time charged to the SEPS [and other business activities]." With regard to building assets, EPIC allocated these assets based on the ratio of capacity of pipelines it owns.[84] Jemena records shared assets using a combination of its asset register, input from engineers, and equipment listing reports with more detailed information than the asset register where relevant.[85]

90. APA and Jemena do not disclose the calculations actually performed to implement these allocations (for example, the total amount of shared cost and the proportions of this total allocated to each pipeline is not disclosed). SEA Gas provides the allocation percentages between its two pipelines (Port Campbell to Adelaide Pipeline and Port Campbell to Iona Pipeline, both have disclosure obligations under Part 23).[86] EPIC also provides the calculation underlying its allocator which is the ratio of the capacity of its two pipelines (South Eastern Pipeline System and Moomba to Adelaide Pipeline System, with only the Moomba to Adelaide Pipeline System having disclosure obligation under Part 23).[87]

91. APA differs from other service providers in that it "does not allocate corporate costs to individual non-scheme pipelines or business segments in its financial reporting systems. APA engaged an expert global auditing and advisory firm to undertake an independent benchmarking analysis to estimate the efficient amount of corporate costs that would be incurred by a firm operating a business of a size and complexity equivalent to the size and complexity of the non-scheme pipeline in the context of a workably competitive market. Where the expert has prepared a bespoke analysis for the relevant pipeline, APA has applied these findings directly without amendment".[88]

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82 Jemena Basis of Preparation – Darling Downs Pipeline, p. 15; Jemena Basis of Preparation – Eastern Gas Pipeline, p. 15; Jemena Basis of Preparation – Queensland Gas Pipeline, p. 15.

83 Note that Jemena does not allocate shared costs to its VicHub Pipeline, "as the underlying drivers for cost allocation to VicHub is [sic] negligible." Jemena Basis of Preparation – VicHub Pipeline, p. 11.

84 EPIC Basis of Preparation – Moomba to Adelaide pipeline, p. 11.

85 Jemena Basis of Preparation – Eastern Gas Pipeline, p. 39, Jemena Basis of Preparation – Darling Downs Pipeline, p. 32, Jemena Basis of Preparation – Queensland Gas Pipeline, p. 33, Jemena Basis of Preparation – VicHub, p. 26.

86 SEA Gas Basis of Preparation, pp. 2-6.

87 EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 9.

88 APA Basis of Preparation, p. 10.

92. APA also does not allocate its total shared support assets (eg. shared IT systems) among its non-scheme pipelines. "Consistent with [its] approach to corporate costs…, APA has allocated the appropriate amount of corporate shared asset costs to each service provider using a cost allocation method in the context of delivering outcomes consistent with a workably competitive market. A portion of the shared support asset costs has been allocated to the individual service provider, with that portion equal to the amount that would be incurred by a firm operating a business of a size and complexity of the non-scheme pipeline in the context of a workably competitive market. In order to determine the value of supporting assets attributable to each service provider, APA has adopted the same ratio of attributed corporate costs to total APA corporate costs".[89]

93. Further, for pipelines owned by APA, some revenue is generated under agreements across multiple pipelines and needs to be allocated so that revenue for each pipeline can be reported. APA states that its allocator is designed to "take into account regulatory and contractual obligations" associated with each pipeline, and therefore "the allocator that is applied for each revenue item will vary, depending on the specific nature of the Multi Asset Service, and in particular, the non-scheme pipelines involved".[90]

4. The recovered capital method

94. Under the RCM, the value of the pipeline assets at any point in time (year *t*) is calculated as the original construction cost of the pipeline, plus accumulated capital expenditure (from the time that the pipeline was constructed to year *t*), subtracting disposals and the return of capital since the pipeline was constructed. Under this method, the return of capital is not estimated using a conventional depreciation method, but rather, it is the residual of revenue after subtracting operating expenses, return on capital and taxes.

95. Calculating the return of capital requires (i) an estimate of the return on capital which is a function of the asset value and a rate of return and (ii) an estimate of tax liabilities. Service providers take different approaches and use different assumptions in their calculation, as detailed below.

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89 APA Basis of Preparation, p. 15.

90 APA uses an allocation methodology for "Multi Asset Services." "Any revenue that is generated under agreements that do not separate the revenue by pipeline [Multi Asset Services] has been allocated to each pipeline using an appropriate allocator or allocators." "The allocation methodology for Multi Asset Services is designed to take into account regulatory and contractual obligations which dictate the tariffs that would be charged on the individual pipelines used to supply a Multi Asset Service. For example, where a pipeline covered by light regulation (such as the Carpentaria Gas Pipeline) is used to supply a Multi Asset Service, the amount of revenue allocated to that pipeline in connection with the Multi Asset Service would reflect the relevant non-discriminatory tariff offered on that pipeline. Consequently, the allocator that is applied for each revenue item will vary, depending on the specific nature of the Multi Asset Service, and in particular, the non-scheme pipelines involved." APA Basis of Preparation, pp. 7-8.

Asset value

96. Other than EPIC, service providers obtain construction costs from their own reporting systems (referred to in the BoP as financial accounting systems, fixed asset registers, or financial statements).[91] EPIC used the Optimized Depreciated Replacement Cost (ODRC) value determined by the Australian Competition Tribunal (ACT) on December 10, 2003 (when the pipeline was a covered pipeline).[92] This means the reported figure by EPIC does not reflect the actual construction cost of the pipeline.

97. The inclusion of capex is different between Jemena and APA and other pipeline owners. Jemena escalates its capital expenditure to a mid-year point using its rate of return estimate to account for the return on capital expenditure incurred during the year, which it calls "gross capex".[93] For all its pipelines, APA states that capital expenditure earns a half-year return in the year the capital expenditure is incurred.[94] Other pipelines do not mention this adjustment.

98. The AER Guideline requires that the rate of return be applied to the closing value of the capital base from the immediately preceding year.[95] APA assumes in its RCM calculations that "the total capital held by the business in any year equals the opening value of the RCM capital base plus half the current year capital expenditure".[96] APA notes that this "cannot be

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91 APA notes that for assets that it acquired, the original construction cost was derived from a number of sources, including fixed asset registers and accounting system information acquired from the vendor on the transaction, public statutory account information from the Australian Securities and Investments Commission (ASIC) website, government websites, or other public sources. Jemena notes that for the EGP, which was commissioned in 1998 but only acquired by Jemena in 2007, construction costs were calculated from Westcoast Energy's 1998 annual report. Westcoast Energy's annual report provided the value of the sale of its 50 percent share in EGP and of its net income from the sale, and from these figures Jemena calculates the implied original construction cost of the pipeline. See APA Basis of Preparation, p.13 and Jemena Basis of Preparation – Eastern Gas Pipeline, p. 31.

92 EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 14.

93 Jemena Basis of Preparation – Eastern Gas Pipeline, p. 32; Jemena Basis of Preparation – Darling Downs Pipeline, p. 28; Jemena Basis of Preparation – VicHub Pipeline, p. 22; Jemena Basis of Preparation - Queensland Gas Pipeline, pp. 29-30.

94 APA Basis of Preparation, p. 17.

95 AER Guideline, p. 20.

96 APA Basis of Preparation, p. 16.

read from the statutory financial statements".[97] Jemena and SEA Gas calculate the capital base on the prior year closing asset value, in accordance with the AER Guideline.[98,99]

Rate of return

99. The AER Guideline does not specify how the commercial rate of return is to be estimated, but service providers are required to report the method, principles and assumptions they used to arrive at their rate of return value.[100] The AER Guideline requires that the rate of return estimate be commensurate with the prevailing conditions in the market for funds and reflect the risks associated with the provision of pipeline services.[101]

100. For all service providers, a rate of return is estimated as the weighted average of the cost of equity and cost of debt. The assumptions underlying the estimation of cost of equity and cost of debt and the assumption about capital structure vary across service providers. It is not possible to estimate the rate of return for each pipeline based only on the information provided in the BoP; however, rates of return can be inferred from the information disclosed under the RCM.

101. With regard to the cost of equity, SEA Gas relies on the post-tax return on equity from regulatory determinations, adding a "risk premium as applicable for the circumstances that SEA Gas faced".[102] Similarly, Palisade states that "[n]otional return on equity is calculated using a regulated cost of equity plus a commercial rate of return".[103] EPIC also relies on regulatory determinations (by the ACCC). Jemena and APA use the CAPM to estimate the cost of equity; however, the exact inputs for the market risk premium, beta and risk free rate vary. For example, APA estimates the risk-free rate using a data set sourced from a 2012 journal article.[104] In contrast, Jemena estimates the risk-free rate using the yield on 10-year Australian government bonds.[105] APA assumes a beta value of 1.[106] Jemena estimates beta by

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97 APA Basis of Preparation, p. 16.

98 Jemena Basis of Preparation – Eastern Gas Pipeline, p. 47; Jemena Basis of Preparation – Queensland Gas Pipeline, p. 39; Jemena Basis of Preparation – VicHub Pipeline, p. 31; Jemena Basis of Preparation – Darling Downs Pipeline, p. 35.

99 SEA Gas Basis of Preparation, p. 7.

100 AER Explanatory Statement, p. 25.

101 AER Guideline, p. 20.

102 SEA Gas Basis of Preparation, p. 7.

103 Palisade Basis of Preparation – Tasmanian Gas Pipeline, p. 4.

104 APA Basis of Preparation, p.17. APA's source is: T. Brailsford, John C. Handley, and Krishnan Maheswaran, "The historical equity risk premium in Australia: Post—GFC and 128 years of data", *Accounting and Finance*, 52(1), 2012: 237–247.

105 See for example, Jemena Basis of Preparation – Eastern Gas Pipeline, p.50.

106 APA Basis of Preparation, p.18.

taking the difference in betas between businesses with unregulated revenues and businesses with regulated revenues, and adding this difference onto the regulatory asset betas adopted by the ACCC and AER.[107]

102. Different service providers use different sources of information to estimate the cost of debt.

    a. APA relies on an expert firm to estimate its cost of debt: "A market interest rate was determined by an expert firm in the financial services sector, reflecting the opportunities for a business such as the service provider to raise capital, including any adjustments to the gearing ratio that may be required. This analysis allowed a market return on debt to be estimated, having regard to the observed spread above a well-reported swap rate and a premium applied for smaller size and single-asset businesses. The expert firm has calculated a cost of debt for all years included in the RCM analysis".[108]

    b. Palisade assumes the notional cost of debt to be in line with historical regulatory determinations over the period. It does not state the exact regulatory determinations on which it relies. SEA Gas uses "the observable market cost of debt from 2004 – 2018". SEA Gas states that it "has this information through its experience in managing debt and swap margins".[109] Jemena estimates cost of debt using the yield on corporate bonds with a broad BBB rating, and terms ranging from one to 10 years.[110]

    c. EPIC relies on the ACCC and AER's methods to estimate its return on debt.[111]

103. Different service providers also assume different capital structure in their calculation of the return on capital.

    a. APA received advice from an independent expert firm on the appropriate capital structure for a business of equivalent size to each non-scheme pipeline. APA states that "[t]he original construction cost of the pipeline is considered to be funded according to the expert firm's recommended capital structure. However, the capital structure may be amended through the RCM analysis. In particular, where the RCM analysis shows

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107 See for example, Jemena Basis of Preparation – Eastern Gas Pipeline, p. 48.

108 APA Basis of Preparation, p. 17.

109 SEA Gas Basis of Preparation, p. 7.

110 Jemena Basis of Preparation – Darling Downs Pipeline, pp. 37–38; Jemena Basis of Preparation – Eastern Gas Pipeline, pp. 48–49; Jemena Basis of Preparation – Queensland Gas Pipeline, pp. 41–42; Jemena Basis of Preparation – VicHub Pipeline, pp. 32–33.

111 From 2001 to 2005, it uses the ACCC determination. From 2006 to 2017, it also relies on the ACCC determination but updates the risk free rate and debt risk premium each reporting period. For 2018, EPIC calculates the return on debt using the method applied by the AER. This method calculates the simple average of the Bloomberg and Reserve Bank of Australia fair value yields for the broad BBB credit rating band at a term to maturity of ten years. EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, pp. 17–18; EPIC Standing Price Information – Moomba to Adelaide Pipeline System, p. 2.

a revenue shortfall,[] this shortfall is modelled to be made up by additional contributions from equity holders rather than by additional borrowing (following the well accepted principle that lenders will not finance losses)".[112] There is no other information on what the exact capital structure APA uses based on this approach.

b. SEA Gas assumes a constant leverage ratio of 60% for each year since a 60% leverage ratio is a "long-standing benchmark" for the Australian pipeline industry in Australia if businesses have a reliable and stable income stream.[113]

c. Jemena assumes a constant leverage 50% over time, stating that this value "reflects reliance on the regulatory risk assumption" but takes into account the fact the leverage adopted by unregulated businesses tends to be lower than that of regulated businesses.[114]

d. EPIC relies on the ACCC and AER determinations for the leverage input in the calculation of the WACC from 2001–2017, which uses a gearing ratio of 60%. There is no mention of the method used to estimate the leverage ratio in 2018.[115]

Net tax liabilities

104. The AER specifies two options for service providers to estimate the net tax liabilities. The first option is to use a pre-tax commercial rate of return and the second option is the post-tax approach with net tax liabilities modelled explicitly.[116] Service providers are required to specify the method, principles, assumptions and inputs used to calculate the net tax liability in their BoP.[117] None of the Part 23 pipeline service providers in this report use the pre-tax commercial rate of return method.

105. Palisade reports zero net tax liabilities for the Tasmanian Gas Pipeline on the basis that the pipeline sits within a tax consolidated group.[118] Jemena also indicates that its pipelines are part of a consolidated tax group and do not pay tax as a stand-alone entity; however, Jemena still estimates net tax liabilities using the post-tax approach.[119] EPIC, APA, and SEA Gas also

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112 APA Basis of Preparation, pp. 16–17.

113 SEA Gas Basis of Preparation, p. 7.

114 Jemena Basis of Preparation – Darling Downs Pipeline, p. 36; Jemena Basis of Preparation – Eastern Gas Pipeline, pp. 47–48; Jemena Basis of Preparation – Queensland Gas Pipeline, p. 40; Jemena Basis of Preparation – VicHub Pipeline, pp. 31–32.

115 EPIC Basis of Preparation – Moomba to Adelaide Pipeline, p. 17; Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System, p. 33.

116 AER Explanatory Statement, p. 25.

117 AER Explanatory Statement, p. 25.

118 Palisade Basis of Preparation – Tasmanian Gas Pipeline, p. 4.

119 See for example, Jemena Basis of Preparation – Darling Downs Pipeline, p. 34.

use the post-tax approach and model net tax liabilities. EPIC primarily relies on the ACCC determination for its net tax liabilities from 2001 to 2005 and only performs its own modelling for 2006 onwards[120]. SEA Gas did not provide a detailed explanation of its approach but stated that it is a tax flow through entity[121] (ie, it does not pay any income tax, but remits pre-tax income directly to its investors) and so the actual taxation position of the investors is unknown and any estimates could not be relied upon.[122]

106. In general, the post-tax approach (i) starts with revenue, (ii) subtracts operating expenses, (iii) subtracts interest expenses (which is estimated using the assumptions to the calculation of return on capital, as opposed to actual cost of debt or capital structure), (iv) subtracts tax depreciation, and then (v) multiplies by the prevailing tax rate.[123]

107. Within the post-tax approach, different service providers use different assumptions to estimate their tax liabilities. In particular:

    a. For the calculation of tax depreciation, EPIC uses "tax depreciation schedules from the ACCC determination… updated for annual capital expenditure by asset class".[124] Other service providers use straight line depreciation. The tax asset lives used by different service providers are likely to be different. For example, APA applies a tax asset life of 20 years. Jemena does not report its assumed tax asset life, but does provide a brief explanation on how it chooses tax asset life. For Darling Downs Pipeline, Jemena states that it chose a "tax asset life [that] most closely aligns calculated tax depreciation across all component pipelines over 2013 to 2016 with Jemena Group's reported accounting depreciation".[125] For Queensland Gas Pipeline and Eastern Gas Pipeline, the tax asset life is chosen to align with tax depreciation.[126]

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120 EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 17.

121 SEA Gas Basis of Preparation, p. 7.

122 SEA Gas Basis of Preparation, p. 8.

123 Jemena states that it uses a tax rate of 30%. Jemena Basis of Preparation – Eastern Gas Pipeline, p. 46, Jemena Basis of Preparation – Darling Downs Pipeline, p. 47, Jemena Basis of Preparation – Queensland Gas Pipeline, p. 36, Jemena Basis of Preparation – VicHub Pipeline, p. 40. Other service providers do not report the rate.

124 EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 17.

125 Jemena Basis of Preparation – Darling Downs Pipeline, p. 34. Jemena also notes that "When estimating each year's tax depreciation, current year net capex was assumed to be incurred mid-year and therefore only a half year of tax depreciation was incurred.

126 For EGP, tax useful life "was estimated based on a useful life that align [*sic*] with tax depreciation amounts for 2007–2018 sourced from the SAP Fixed Asset Tax Register." Jemena Basis of Preparation – Eastern Gas Pipeline, p. 46. For QGP, "[t]ax useful life was estimated based on a useful life that align [*sic*] with tax depreciation amounts for 2005 sourced from the SAP Fixed Asset Tax Register." Jemena Basis of Preparation – Queensland Gas Pipeline, p. 37.

b. EPIC and APA note that tax losses are accumulated and used to offset against future net tax liabilities. Jemena and SEA Gas do not mention accumulated tax losses.

c. Jemena does not include imputation credits in its calculation of net tax liabilities.[127] Neither APA nor SEA mentions imputation credits in its BoP. EPIC is the only service provider that states in its BoP that it includes imputation credits in its calculation of net tax liabilities. EPIC reduces gross tax payable by gamma of 0.4 to reflect "the regulatory approach to include the value of imputation credits in the tax liability for the service provider".[128]

B. A review of reported information

108. In this section, we summarise our review of the Part 23 financial information. Our summary starts with the reporting of asset value, followed by expenses, revenue and weighted average prices. The AER Guideline requires that related party transactions be reported separately in the Statement of Pipeline Revenue and Expenses and in the Statement of Pipeline Assets.[129] Our summary also documents the magnitude of related party transactions reported across pipelines.

109. The AER Template requires service providers to report similar information in multiple places. For example, revenue is reported in the "Statement of revenue and expenses", and also for the calculation of weighted average prices. Capital expenditure is reported under the depreciated book value method and the RCM. In our summary tables of the reported information, we include in the names of the data items the table number within the AER Template where the data items come from. We compute additional variables to analyse the reported information. These additional variables we label with just the names we assign to the variables and, where appropriate, an indication of how these variables were estimated.

1. Other differences

110. For the Moomba to Sydney Pipeline, the reported information includes information related to the parts of the pipelines not covered under Part 23. APA considers "that preparing financial reports for only the non-scheme components of the MSP [Moomba to Sydney Pipeline] presents scope for misunderstanding, as this is not consistent with the way customers contract for gas transportation on the MSP. APA has therefore presented this [Part 23] information for the whole pipeline system".[130]

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127 Jemena Basis of Preparation – Darling Downs Pipeline, p. 34.

128 EPIC Basis of Preparation – Moomba to Adelaide Pipeline, p. 17.

129 AER Guideline, p. 17.

130 The pipeline system consists of a non-scheme pipeline from Moomba to Marsden, a light regulation pipeline system from Marsden to Sydney with a number of laterals, and an interconnector (non-scheme pipeline) between Wagga and Culcairn. APA Basis of Preparation, pp. 2–3.

2. Pipeline asset value

111. Within the Part 23 financial information, service providers are required to report the value of pipeline assets estimated under two methods: the depreciated book value method and the RCM.[131]

112. The depreciated book value method requires a detailed breakdown of the different asset classes (such as pipelines, compressors, metering etc.).[132] For each asset class, service providers are required to report the construction or acquisition cost, and accumulated depreciation, additions and disposals since construction or acquisition. The current asset value under the depreciated book value method reflects straight line depreciation of the construction or acquisition cost. For the RCM, service providers are required to report the construction cost, additions and disposals for two broad categories of assets (direct assets and shared assets) for every year since the construction of the pipeline.[133] The current asset value under the RCM is estimated by reflecting a depreciation calculation where depreciation is the residual after operating expenses, return on capital and an estimate of tax liabilities are subtracted from revenues each year.

a. Asset composition across pipelines

113. Since the reporting of pipeline assets under the depreciated book value method includes a breakdown of shared versus direct assets, as well as the different components within shared assets and direct assets, we use the depreciated book value method reporting[134] to understand the asset composition across pipelines.

114. As indicated in the BoP, different service providers use different methods to allocate their shared assets and shared expenses. This means the magnitude of shared assets (and shared expenses) reported for a pipeline can vary, depending on the allocation methods used by the service providers. Table 1 reports the value of shared and direct assets for each of the fourteen Part 23 pipelines. Table 1 shows that shared assets typically make up a small portion of total assets (approximately 5% or less), except in the case of pipelines owned by Jemena. For Jemena pipelines, shared assets make up 20% to more than 60% of total assets.

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131 AER Explanatory Statement, p. 4.

132 AER Guideline, pp. 11–12.

133 AER Guideline, pp. 18–19.

134 Table 3.1 (worksheet "3. Statement of Pipeline assets") of the AER Template.

Table 1
Shared versus direct assets as at 30 June 2018
(under the depreciated book value method)

	Total assets in Table 3.1	Direct assets in Table 3.1	Shared assets in Table 3.1	Direct assets as % of total assets	Shared assets as % of total assets
	AUD millions	AUD millions	AUD millions	%	%
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	84.7	83.0	1.6	98.1%	1.9%
Goldfields Gas Pipeline	190.7	186.1	4.6	97.6%	2.4%
Moomba to Sydney Pipeline	1,137.6	1,126.9	10.7	99.1%	0.9%
South East South Australia Pipeline	15.3	14.8	0.5	96.4%	3.6%
South West Queensland Pipeline	2,387.2	2,371.9	15.3	99.4%	0.6%
Wallumbilla Gladstone Pipeline	5,451.6	5,426.4	25.1	99.5%	0.5%
Jemena					
Darling Downs Pipeline	495.1	353.5	141.6	71.4%	28.6%
Eastern Gas Pipeline	1,730.8	1,308.7	422.2	75.6%	24.4%
Queensland Gas Pipeline	461.7	215.1	246.6	46.6%	53.4%
VicHub Pipeline	15.0	5.0	10.0	33.6%	66.4%
SEA Gas					
Port Campbell to Adelaide Pipeline	397.0	388.4	8.7	97.8%	2.2%
Port Campbell to Iona Pipeline	13.3	13.1	0.1	99.0%	1.0%
EPIC					
Moomba to Adelaide Pipeline System	371.4	352.3	19.1	94.9%	5.1%
Palisade					
Tasmanian Gas Pipeline	212.6	212.6	0.0	100.0%	0.0%

Sources: Part 23 financial information, October 2018, Table 3.1.
Notes:
[A]: The sum of the depreciated book values at 30 June 2018 of all direct and shared assets attributed to the pipeline.
[B]: The sum of the depreciated book values at 30 June 2018 of direct assets.
[C]: The sum of the depreciated book values at 30 June 2018 of shared assets. Shared assets comprise four categories in the AER Template: "shared property, plant and equipment", "inventories", "deferred tax assets" and "other assets".
[D] = [B] / [A] x 100
[E] = [C] / [A] x 100

115. Table 2 breaks down the different components of shared assets reported across pipelines, as a percentage of total asset value under the depreciated book value method. Table 2 shows that the difference in the proportion of shared assets between Jemena pipelines and others seems to be driven by the fact that Jemena includes certain categories of assets under shared assets that other service providers do not mention. For non-Jemena pipelines, shared assets typically consist of shared property, plant and equipment. Shared assets for all Jemena pipelines comprise largely of "other assets". According to Jemena's BoP, "other assets" include "accrued receivables and amounts due from related parties.[135] In the case of Jemena's Darling Downs Pipeline, shared assets also comprise a substantial amount of "deferred tax assets".

[135] See, for example, Jemena Basis of preparation – Eastern Gas Pipeline, p. 18.

Table 2
Components of shared assets (as a % of total assets) as at 30 June 2018 in Table 3.1

		Shared asset components as % of total assets in Table 3.1			
	Shared assets in Table 3.1	Shared property, plant and equipment in Table 3.1	Inventories in Table 3.1	Deferred tax assets in Table 3.1	Other assets in Table 3.1
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	1.9%	1.9%	0.0%	0.0%	0.0%
Goldfields Gas Pipeline	2.4%	2.4%	0.0%	0.0%	0.0%
Moomba to Sydney Pipeline	0.9%	0.9%	0.0%	0.0%	0.0%
South East South Australia Pipeline	3.6%	3.6%	0.0%	0.0%	0.0%
South West Queensland Pipeline	0.6%	0.6%	0.0%	0.0%	0.0%
Wallumbilla Gladstone Pipeline	0.5%	0.5%	0.0%	0.0%	0.0%
Jemena					
Darling Downs Pipeline	28.6%	0.0%	0.0%	8.4%	20.2%
Eastern Gas Pipeline	24.4%	0.2%	0.2%	0.0%	23.9%
Queensland Gas Pipeline	53.4%	0.5%	0.3%	0.6%	52.0%
VicHub Pipeline	66.4%	0.0%	0.0%	0.0%	66.4%
SEA Gas					
Port Campbell to Adelaide Pipeline	2.2%	0.6%	0.0%	0.0%	1.6%
Port Campbell to Iona Pipeline	1.0%	0.4%	0.0%	0.0%	0.6%
EPIC					
Moomba to Adelaide Pipeline System	5.1%	1.0%	0.3%	0.0%	3.8%
Palisade					
Tasmanian Gas Pipeline	0.0%	0.0%	0.0%	0.0%	0.0%

Sources: Part 23 financial information, October 2018, Table 3.1.
Notes:
[A] = [B] + [C] + [D] + [E]
[B]: "Shared property, plant and equipment", a component of shared assets, as a percentage of total assets.
[C]: "Inventories", a component of shared assets, as a percentage of total assets.
[D]: "Deferred tax assets", a component of shared assets, as a percentage of total assets.
[E]: "Other assets", a component of shared assets, as a percentage of total assets.

116. Table 3 breaks down the different components of direct assets, as a percentage of total asset value reported under the depreciated book value method. There are several asset classes within direct assets, including pipeline, compressors, city gates, metering, odourant plants, and SCADA. These are collectively referred to as "depreciable direct assets" in Table 3. Direct pipeline assets also include land and easements[136] and "other non-depreciable assets". Also,

[136] The AER's Guideline does not provide for land or easements to be depreciated. The AER acknowledges that "[s]ome service providers have, however, indicated that easements may have a fixed term life (AER Explanatory Statement, p. 17). Two service note in their BoP that they disagree with the AER's treatment of depreciation for easements. Palisade states "[e]asements are recorded at cost, being the present value of identified net cash flow streams (including renewal options) and are amortised on a straight line based over the estimated lives (in line with the expected useful life of the pipeline). TGP

as we noted in our summary of the BoP in section IV.A, APA appears to include some shared costs as direct costs.[137] Table 3 shows that some pipelines report a large amount of "other non-depreciable assets". For example, 54 and 44 percent of the total assets of Wallumbilla Gladstone Pipeline (owned by APA) and Eastern Gas Pipeline (owned by Jemena) is made up of "other non-depreciable assets". Jemena explains in the BoP for Eastern Gas Pipeline that non-depreciable assets include goodwill at a group entity level allocated to each pipeline.[138] APA does not provide an explanation for the amount of non-depreciable assets it reports in its BoP. We would assume that these figures include capitalisation of long-term transportation contracts.[139]

note, amortisation of easements is not included as a calculation formula in the AER Template. This is a divergence from the recognition and measurement requirements specified by all Australian Accounting Standards and Interpretations." (See Palisade, Basis of Preparation – Tasmanian Gas Pipeline, 2018, p. 3.) Palisade did not include amortization for easements Table 3 of the AER Template (depreciated book value of assets) as the template does not allow for depreciation of easement; however, Palisade did report the amortized amount under the table 3.1.1 (depreciation). Jemena also notes that it does depreciate easements. (See Jemena, Basis of Preparation – Eastern Gas Pipeline, 2018, p. 28; Jemena, Basis of Preparation – Queensland Gas Pipeline, 2018, p. 26. Darling Downs Pipeline and VicHub do not mention easements in their respective BoP, but according to their financial disclosures there are also no easements attributable to these pipelines.)

137 This refers to what APA calls "other attributable costs", as noted in section IV.A.

138 Jemena Basis of Preparation – Eastern Gas Pipeline, 2018, p. 18. ("The SGSPAA Group consolidates its resulting Goodwill from acquisitions at a SGSPAA Group entity level, meaning that it does not pass-on any Goodwill into its subsidiary entities. These SGSPAA Group adjustments are maintained in an excel spreadsheet outside the SGSPAA Group's SAP system and allocated to the SGSPAA Group's cash generating units (e.g., pipelines) for the purpose of impairment testing, in accordance with Australian Accounting Standards. The Guideline does not restrict consideration to only those assets identifiable at the direct pipeline owning entity level and accordingly EGP allocated Goodwill to the pipeline in its statement of assets. EGP considered this a reasonable allocation and disclosure.")

139 APA's FY2015 financial report indicates that it acquired Wallumbilla Gladstone Pipeline for approximately AUD 5.9 billion, with the amount of "contract and other intangibles" increasing from AUD 677 million to AUD 3.4 billion due to acquisitions/additions. See APA Group Annual Report for the financial year ended 30 June 2015, pp. 16, 74.

Table 3
Components of direct assets (as a % of total assets) as at 30 June 2018 in Table 3.1

		Direct asset components as % of total assets in Table 3.1		
	Direct assets in Table 3.1	Depreciable direct assets in Table 3.1	Other non-depreciable assets in Table 3.1	Land and easements in Table 3.1
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	98.1%	96.4%	1.5%	0.1%
Goldfields Gas Pipeline	97.6%	97.6%	0.0%	0.0%
Moomba to Sydney Pipeline	99.1%	83.5%	15.4%	0.1%
South East South Australia Pipeline	96.4%	95.0%	1.4%	0.0%
South West Queensland Pipeline	99.4%	67.3%	32.0%	0.0%
Wallumbilla Gladstone Pipeline	99.5%	45.2%	54.2%	0.2%
Jemena				
Darling Downs Pipeline	71.4%	66.3%	5.1%	0.0%
Eastern Gas Pipeline	75.6%	30.8%	44.0%	0.8%
Queensland Gas Pipeline	46.6%	42.8%	2.4%	1.4%
VicHub Pipeline	33.6%	33.6%	0.0%	0.0%
SEA Gas				
Port Campbell to Adelaide Pipeline	97.8%	96.3%	0.0%	1.5%
Port Campbell to Iona Pipeline	99.0%	98.2%	0.0%	0.7%
EPIC				
Moomba to Adelaide Pipeline System	94.9%	93.7%	0.6%	0.6%
Palisade				
Tasmanian Gas Pipeline	100.0%	90.2%	0.0%	9.8%

Sources: Part 23 financial information, October 2018, Table 3.1.
Notes:
[A] = [B] + [C] + [D]
[B]: Depreciable direct assets (including pipeline, compressors, city gates, metering, odourant plants, SCADA, buildings and "other depreciable pipeline [direct] assets") as a percentage of total assets.
[C]: "Other non-depreciable assets", a component of direct assets, as a percentage of total assets.
[D]: "Land and easements", a component of direct assets, as a percentage of total assets.

117. Table 4 summarises the magnitude of total assets and direct assets of each pipeline with and without "other non-depreciable assets". The inclusion of "other non-depreciable assets" has a large impact on the asset value of a number of pipelines, including Wallumbilla Gladstone Pipeline, Eastern Gas Pipeline and South West Queensland Pipeline.

Table 4
Total and direct assets excluding other non-depreciable assets

	Total assets in Table 3.1	Direct assets in Table 3.1	Other non-depreciable assets in Table 3.1	Total assets excluding other non-depreciable in Table 3.1	Direct assets excluding other non-depreciable in Table 3.1
	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	84.7	83.0	1.3	83.4	81.8
Goldfields Gas Pipeline	190.7	186.1	0.0	190.7	186.1
Moomba to Sydney Pipeline	1,137.6	1,126.9	175.7	961.9	951.3
South East South Australia Pipeline	15.3	14.8	0.2	15.1	14.5
South West Queensland Pipeline	2,387.2	2,371.9	764.2	1,623.1	1,607.8
Wallumbilla Gladstone Pipeline	5,451.6	5,426.4	2,954.0	2,497.6	2,472.4
Jemena					
Darling Downs Pipeline	495.1	353.5	25.3	469.8	328.2
Eastern Gas Pipeline	1,730.8	1,308.7	761.0	969.8	547.7
Queensland Gas Pipeline	461.7	215.1	10.9	450.7	204.1
VicHub Pipeline	15.0	5.0	0.0	15.0	5.0
SEA Gas					
Port Campbell to Adelaide Pipeline	397.0	388.4	0.0	397.0	388.4
Port Campbell to Iona Pipeline	13.3	13.1	0.0	13.3	13.1
EPIC					
Moomba to Adelaide Pipeline System	371.4	352.3	2.2	369.2	350.1
Palisade					
Tasmanian Gas Pipeline	212.6	212.6	0.0	212.6	212.6

Sources: Part 23 financial information, October 2018, Table 3.1.
Notes:
[A]: The sum of the depreciated book values at 30 June 2018 of all direct and shared assets attributed to the pipeline.
[B]: The sum of the depreciated book values at 30 June 2018 of direct assets.
[C]: The depreciated book value of "other non-depreciable pipeline [direct] assets" in Table 3.1.
[D] = [A] - [C]
[E] = [B] - [C]

b. Depreciated book value method—information reporting

118. The information underlying the depreciated book value of assets is reported in two places in the AER Template: "Statement of pipeline assets" (Table 3.1 in the AER Template) and "Depreciation" (Table 3.3.1, "Fixed assets at cost – pipeline assets", and Table 3.3.2, "Shared assets at cost (less straight line depreciation)", in the AER Template, collectively referred to as Table 3.3). While Table 3.1 in the template references Table 3.3, the labelling of information is inconsistent between the two tables. To illustrate this, Table 5 summarises the sum of construction and acquisition costs across the different asset classes reported in Table 3.1 and Table 3.3. For the construction and acquisition costs in Table 3.1, we include all line items with the title "initial construction cost", "initial purchase costs", or "initial purchase/improvement cost", as well as "shared property, plant and equipment at cost".

Table 5
Comparison of construction cost reporting in Tables 3.1 and 3.3

	Construction and acquisition costs in Table 3.1	Construction and acquisition costs based on Table 3.3	What explains the difference?
	AUD millions	AUD millions	
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	91.6	91.6	No difference
Goldfields Gas Pipeline	13.3	13.3	No difference
Moomba to Sydney Pipeline	803.9	803.9	No difference
South East South Australia Pipeline	18.0	18.0	No difference
South West Queensland Pipeline	1,374.2	1,374.2	No difference
Wallumbilla Gladstone Pipeline	2,599.1	2,599.1	No difference
Jemena			
Darling Downs Pipeline	357.1	356.9	Other depreciable direct assets additions
Eastern Gas Pipeline	732.8	726.5	Other depreciable direct assets additions
Queensland Gas Pipeline	166.2	160.8	Other depreciable direct assets additions
VicHub Pipeline	9.2	9.2	No difference
SEA Gas			
Port Campbell to Adelaide Pipeline	469.1	475.3	Other asset and shared asset construction costs
Port Campbell to Iona Pipeline	9.2	9.3	Other asset construction costs
EPIC			
Moomba to Adelaide Pipeline System	381.5	378.6	Other depreciable direct assets additions
Palisade			
Tasmanian Gas Pipeline	302.5	302.5	No difference

Sources: Part 23 financial information, October 2018, Tables 3.1, 3.3.1 and 3.3.2.
Notes:
[A]: The sum of construction cost categories in Table 3.1. This includes “Other depreciable pipeline assets - Initial purchase/improvement cost” and “Shared property, plant and equipment at cost”.
[B]: The sum of construction and acquisition cost categories in Tables 3.3.1 and 3.3.2.
[C]: "Other depreciable direct assets additions" means that the difference between [A] and [B] is caused by the inclusion of “[a]dditions” in the “[i]nitial purchase/improvement cost” line item for “other depreciable pipeline [direct] assets” in Table 3.1. "Other asset [and/or shared asset] construction costs" means that the difference is caused by the inclusion of shared and/or other asset construction costs in the item "Other assets" in Table 3.1.

119. Table 5 shows that if we just look at what appears to be construction and acquisition costs of pipeline assets, the information in Table 3.1 and Table 3.3 of the AER Template might not be the same. For example, there are some small differences in the sum of construction and acquisition cost in the two tables for three pipelines owned by Jemena and Moomba to Adelaide Pipeline System (owned by EPIC). This is because the information in Table 3.1 is less detailed than that in Table 3.3 for some asset classes. In Table 3.3, construction or acquisition costs and additions are listed separately for each asset class. This is the same in Table 3.1 for most asset classes but not “other depreciable pipeline assets”. For most asset classes, Table 3.1 starts with construction or acquisition cost, then additions and capitalised maintenance or improvements, depreciation and disposals, which together are used to arrive at the current value (or the “closing carrying value”) of the asset class. However, for “other depreciable pipeline assets”, Table 3.1 only has “initial purchase/improvement cost”, depreciation and disposals, and no entry for additions. As a result, Jemena and EPIC add construction or acquisition cost and additions together, and report this sum under “initial

purchase/improvement cost" for "other depreciable pipeline assets" in Table 3.1. Therefore, when trying to identify construction or acquisition cost in Table 3.1, our numbers also include Jemena's and EPIC's additions for "other depreciable pipeline assets". This is not the case when we calculate construction or acquisition cost in Table 3.3. This is not an issue for APA since APA amends Table 3.1 of the AER Template to insert a separate line for "additions and improvements capitalised" to "other depreciable pipeline assets".[140] Tasmanian Gas Pipeline and VicHub Pipeline report no additions for other depreciable assets, which explains why they also do not have this inconsistency.

120. Similarly, there is also a difference in the sum of construction cost and acquisition cost between Table 3.1 and Table 3.3 for SEA Gas pipelines. This is because of a similar inconsistency in the AER Template between Table 3.1 and Table 3.3 with regard to "other assets". Table 3.3 lists construction or acquisition costs and additions separately for "other assets". Table 3.1 also lists these components separately, as well as depreciation and disposal, for most asset classes but not "other assets" (this is the same inconsistency as we described above for "other depreciable pipeline assets"). For "other assets", Table 3.1 only has one entry for the current asset value. Therefore, when trying to identify construction cost or acquisition cost in Table 3.1, we were not able to include this information for "other assets".

121. Further, Table 3.3 is made up of two tables, Table 3.3.1 and Table 3.3.2, for "fixed assets" and "shared assets" respectively. However, SEA Gas reports "property plant and equipment", which it categorises as "shared supporting assets" in both Tables 3.3.1 and 3.3.2. We do not understand why SEA Gas reports these different items of "property plant and equipment" separately in Table 3.3. When importing information related to "property plant and equipment" from Table 3.3 to Table 3.1, SEA Gas reports the construction cost of the "property plant and equipment" items in Table 3.3.2 under "Shared supporting assets" in Table 3.1, but reports the closing value of "property plant and equipment" from Table 3.3.1 under "Other assets" in Table 3.1. Again, we do not understand why a distinction is made between these items of "property plant and equipment".

122. The inconsistencies discuss above do not necessarily result in any inaccuracy in the reported information. The differences in the values reported in Table 5 are also not of substantial magnitude. However, we suggest that the AER Template should be consistent across different tables that ask for the same information. This will make it more straightforward to interpret and use the information, as well as simplify the reporting of the information for service providers.

123. In addition, the wording in the AER Template Table 3.3.1 and 3.3.2 with regard to depreciation appears to be unclear, at least judging from the information reported by different service providers. In Table 3.3.1, service providers are required to report "Prior years' accumulated depreciation" and "Current year accumulated depreciation". In Table 3.3.2, service providers are required to report "Depreciation". It is not clear why the AER

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[140] See, for example, APA, Berwyndale Wallumbilla Pipeline Part 23 financial information, October 2018, worksheet "APA Amendments to template".

uses different wordings across the two tables. Further, it appears that service providers are not clear on what needs to be reported in Table 3.3.1. Table 6 summarises the reporting of depreciation in Table 3.3.1. Table 6 shows that APA appears to report cumulative depreciation for "Prior years' accumulated depreciation" and *current year* depreciation for "Current year accumulated depreciation" (since column [B] for APA is smaller in magnitude than column [A]). Jemena and SEA Gas do not report "Prior years' accumulated depreciation" and only report "Current year accumulated depreciation". Palisade appears to report cumulative depreciation under both fields.

Table 6
Prior years' and current period depreciation reported in Table 3.3.1

	Prior years' accumulated direct asset depreciation in Table 3.3.1	Current year accumulated direct asset depreciation in Table 3.3.1
	AUD millions	AUD millions
	[A]	[B]
APA		
Berwyndale Wallumbilla Pipeline	9.1	0.6
Goldfields Gas Pipeline	31.6	3.1
Moomba to Sydney Pipeline	212.9	8.1
South East South Australia Pipeline	3.6	0.2
South West Queensland Pipeline	125.8	14.5
Wallumbilla Gladstone Pipeline	83.7	16.2
Jemena		
Darling Downs Pipeline	0.0	46.9
Eastern Gas Pipeline	0.0	330.4
Queensland Gas Pipeline	0.0	153.0
VicHub Pipeline	0.0	4.2
SEA Gas		
Port Campbell to Adelaide Pipeline	0.0	92.2
Port Campbell to Iona Pipeline	0.0	5.6
EPIC		
Moomba to Adelaide Pipeline System	0.0	83.4
Palisade		
Tasmanian Gas Pipeline	84.9	89.9

Sources: Part 23 financial information, October 2018, Table 3.3.1.
Notes:
[A]: The sum of "prior years' accumulated depreciation" for all asset categories reported in Table 3.3.1.
[B]: The sum of "current year accumulated depreciation" for all asset categories reported in Table 3.3.1.

c. Depreciated book value method—asset lives

124. The AER Guideline requires that assets under the depreciated book value method be depreciated in accordance the Australian Accounting Standards.[141] The AER sets out a recommended range of asset lives for each asset class for the purpose of book value depreciation.[142] However, different service providers use different asset lives in their depreciation, and in some cases, the asset lives reported by service providers appear inconsistent with the AER Guideline, as shown in Table 7. It appears that the AER Guideline sets out total asset lives, and service providers report total asset lives rather than the remaining lives of the pipeline assets.

Table 7
Asset useful lives reported by service providers versus the AER Guideline

	APA	Jemena				SEA Gas	EPIC	Palisade	AER - Appendix A
	All pipelines	Queensland Gas Pipeline	Darling Downs Pipeline	Eastern Gas Pipeline	VicHub	All pipelines	Moomba to Adelaide Pipeline	Tasmanian Gas Pipeline	AER common range
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Pipelines	80	40.3	67.1	41.4	38	80	30-40	40-67	60-80
Compressors	35	26.9	33.8	27.8	-	30	30-50	-	30-35
City Gates, supply regulators and valve stations	50	39.8	34.4	41.5	38	30	-	5-40	30-50
Metering	50	19.5	32.9	19.4	20	30	10-40	10-40	30-50
SCADA (Communications)	15	4.8	21.5	7	-	15	10-20	4-15	15-15
Buildings	80	31	33.9	30.9	-	80	30-40	15-40	80-80
IT systems	-	-	-	-	-	-	3-5	-	5-5

Sources and notes:
[A] to [H]: Part 23 financial information, October 2018, Table 3.1.1.
[I]: AER Guideline, Appendix A, p. 29. The ranges in the table are those for transmission pipelines and are reported as they appear in the AER Guideline. Note that ranges for some assets differ for distribution pipelines.

125. APA and SEA Gas are the only service providers with all asset lives falling within the range provided in the AER Guideline. The asset lives reported by other service providers tend to be shorter than those in the AER Guideline.

    a. For Tasmanian Gas Pipeline, Palisade provides ranges of asset lives which typically overlap with those provided by the AER. However, the lower bound of these ranges is significantly shorter than those provided by the AER. For example, for pipelines, the AER Guideline provides a range of 60 to 80 years, and Palisade reports a range of 40 to 67 years for Tasmanian Gas Pipeline. Palisade does not provide further explanation for

141 AER Guideline, p. 4.

142 AER Guideline, p. 29.

its choice of asset lives, other than "[a]ssets falling outside of [the AER Guideline's] range are depreciated over their estimated useful lives".[143]

b. EPIC's reported asset lives for MAPS are shorter than the AER Guideline's common ranges. EPIC states in its BoP that "[t]he MAPS was acquired in 2013 but was originally constructed in 1970… [t]he original pipeline asset lives are within the ranges provided in Appendix A of the Guidelines".[144]

c. Jemena's reported asset lives also tend to be shorter than the AER Guideline's common ranges.[145] In its BoP for the Darling Downs Pipeline, Jemena states that "[t]he economic useful life of individual assets is defined in terms of the Australian Accounting Standards and the asset's expected use to DDP which may not fall within the Guideline's Appendix A – Pipeline asset lives. The estimation of the economic useful life of an asset is a matter of judgement based on the Jemena Group's experience with similar assets. Additionally, economic useful life shall be considered in relation to the life assigned to similar assets within the asset category".[146]

d. The recovered capital method reporting

126. The AER Guideline requires that the RCM be calculated for every year since the construction of the pipeline. However, for some pipelines, there is a difference between the year of construction (reported by the service providers) and the first year of reporting under the RCM.[147] For example, APA reports a construction date of 18 December 1977 for the Moomba to Sydney Pipeline but does not report any construction cost until 18 December 2004[148] and does not explain why this is the case. The reported construction date and the first year of reporting under the RCM for each pipeline are summarised in Table 8.

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143 Palisade Basis of Preparation - Tasmanian Gas Pipeline, 2018, p. 4.

144 EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 11.

145 Jemena's reported useful life for each asset class is a weighted average cost useful life. See, for example, Jemena Basis of Preparation – Eastern Gas Pipeline, 2018, p. 21.

146 Jemena Basis of Preparation – Darling Downs Pipeline, 2018, p. 21.

147 Some pipelines use fiscal year versus calendar year in their RCM calculations. We do not attempt to distinguish this difference in our calculations and summary tables.

148 APA (2018), Part 23 financial information – Moomba to Sydney Pipeline, Tables 4.1 and 4.2.

Table 8
Year of pipeline construction and first reporting year in the RCM

	Construction year in Table 4.2	First year of reporting in Table 4.1
	[A]	[B]
APA		
Berwyndale Wallumbilla Pipeline	2009	2009
Goldfields Gas Pipeline	2005	2005
Moomba to Sydney Pipeline	1977	2004
South East South Australia Pipeline	2005	2005
South West Queensland Pipeline	1995	1995
Wallumbilla Gladstone Pipeline	2014	2015
Jemena		
Darling Downs Pipeline	2005	2005
Eastern Gas Pipeline	1998	1998
Queensland Gas Pipeline	1989	1989
VicHub Pipeline	2003	2003
SEA Gas		
Port Campbell to Adelaide Pipeline	2004	2004
Port Campbell to Iona Pipeline	2004	2004
EPIC		
Moomba to Adelaide Pipeline System	1970	2000
Palisade		
Tasmanian Gas Pipeline	2002	2002

Sources: Part 23 financial information, October 2018, Tables 4.1 and 4.2.
Notes:
[A]: The year of construction reported in Table 4.2 (below Table 4.1).
[B]: The first year for which construction costs are reported in Table 4.1.

127. Our review of the BoP suggests that service providers use different assumptions in their estimation of return on capital under the RCM. While the rates of return are not reported by service providers, we can estimate the rates of return on investment assumed by each pipeline from the reporting under the RCM.

128. Table 9 illustrates how we estimate the rates of return on investment, using the Moomba to Adelaide pipeline from 2000 to 2004 as an example. As part of the AER Template, service providers report the initial construction cost (row [A]), and the change in asset value (row [B]) for every year since construction. This allows us to estimate the opening asset value (row [C]) for every year since the construction of the pipeline. Service providers are also required to provide an estimate of the return on capital for each year (row [D]). We estimate the rate of return on investment as the ratio of the return on capital in a given year and the opening

asset value of that year (which is equivalent to the closing value from the preceding year, as per the AER Guideline).[149]

Table 9
Inferring rates of return from the RCM

Moomba to Adelaide Pipeline System		Units	2000	2001	2002	2003	2004
Construction cost in Table 4.1	[A]	AUD millions	380.9	0.0	0.0	0.0	0.0
Annual change in asset value in Table 4.1	[B]	AUD millions	380.9	2.3	2.5	-3.6	-2.8
Opening asset value	[C]	AUD millions	0.0	380.9	383.2	385.8	382.1
Return on capital in Table 4.1	[D]	AUD millions	0.0	33.7	33.5	33.4	33.2
Rate of return on opening asset value	[E]	%	NA	8.8%	8.7%	8.6%	8.7%

Sources: Part 23 financial information, October 2018, Table 4.1.
Notes:
[A]: The sum of construction costs for direct and shared assets reported in Table 4.1.
[B]: The annual change in asset value reported in Table 4.1.
[C](t) = [C](t - 1) + [B](t – 1)
[D]: The return on capital reported in Table 4.1.
[E](t) = [D](t) / [C](t)

129. The estimation of the rate of return on capital is not straightforward for all pipelines. Some service providers appear to have different "timing" in their reporting of the return on capital component. Table 10 summarises the RCM information for two pipelines, Berwyndale Wallumbilla (owned by APA) and Darling Downs (owned by Jemena). Table 10 shows that Jemena reports the first return on capital one year after the first construction cost whereas APA reports the first return on capital in the same year as the first construction cost. Jemena states in its BoP that it escalates its capital expenditure to a mid-year point.[150] APA states that capital expenditure earns a half-year return in the year the capital expenditure is incurred.[151] While both Jemena and APA appear to allow for a return on capital expenditure in the same year that the capital expenditure is incurred, it appears that the timing of their reporting of return on capital is different. It appears that APA allows for and reports a return on capital for capital expenditure incurred in the same year, whereas Jemena estimates a "gross capex" in any given year and then reports a return on capital for capital expenditure incurred in the previous year. This means the AUD 4 million reported by APA for Berwyndale Wallumbilla

[149] To calculate the return of capital in the recovered capital method, "the rate of return [is] to be applied to the closing value of the capital base from the immediately preceding year". AER Explanatory Statement, p. 23.

[150] Jemena Basis of Preparation – Eastern Gas Pipeline, p. 32; Jemena Basis of Preparation – Queensland Gas Pipeline, pp. 29-30; Jemena Basis of Preparation – Darling Downs Pipeline, p. 28; Jemena Basis of Preparation - VicHub, p. 22.

[151] APA Basis of Preparation, p. 17.

Pipeline is likely to be an estimate of half-year return on the AUD 79.6 million capital expenditure incurred in 2009, equating to a rate of return on investment of approximately 10% in 2009. Our calculations do not attempt to differentiate and identify the differences in timing and/or reporting methods across different service providers. Rather, we estimate the rates of return that each service provider has given each pipeline in any given year using the reported return on capital figures and the method specified by the AER.

Table 10
Timing differences amongst service providers in the reporting of the RCM

		Units	2005	2006	...	2009	2010	...	2017	2018
Berwyndale Wallumbilla Pipeline (APA)										
Construction cost in Table 4.1	[A]	AUD millions				79.6	0.0	...	0.0	0.0
Annual change in asset value in Table 4.1	[B]	AUD millions				83.2	6.4	...	-2.3	-1.4
Opening asset value	[C]	AUD millions				0.0	83.2	...	99.8	97.5
Return on capital in Table 4.1	[D]	AUD millions				4.0	8.5	...	8.9	8.7
Rate of return on opening asset value	[E]	%					10.2%	...	8.9%	8.9%
Darling Downs Pipeline (Jemena)										
Construction cost in Table 4.1	[F]	AUD millions	26.5	0.0	...	0.0	154.2	...	0.0	0.0
Annual change in asset value in Table 4.1	[G]	AUD millions	27.0	3.5	...	-2.4	154.2	...	26.7	-2.5
Opening asset value	[H]	AUD millions	0.0	27.0	...	33.3	30.9	...	169.8	196.4
Return on capital in Table 4.1	[I]	AUD millions	0.0	2.4	...	3.1	2.9	...	13.6	7.5
Rate of return on opening asset value	[J]	%		9.0%	...	9.2%	9.4%	...	8.0%	3.8%

Sources: Part 23 financial information, October 2018, Table 4.1.
Notes:
[A] and [F]: The sum of construction costs for total assets in a given year in Table 4.1.
[B] and [G]: The annual change in total asset value in a given year in Table 4.1, calculated as the sum of construction costs, capital expenditure and negative residual value less disposals and return of capital.
[C] and [H]: The asset value at the beginning of a given year as calculated in the recovered capital method, equivalent to the previous year's closing asset value.
[D] and [I]: The return on capital in a given year.
[E] = [D] / [C] x 100
[J] = [I] / [H] x 100

130. Table 10 also shows the inferred rate of return in 2018 for Darling Downs Pipeline is approximately half of that in 2017, which is not the case for Berwyndale Wallumbilla Pipeline. The three other Jemena pipelines produce similar results in 2018 relative to prior years (see Table 12). This might be because the reporting period is for the six months ending 30 June 2018,[152] but the RCM calculation is reported on an annual basis. Therefore, it appears

[152] The National Gas (Pipelines Access Arbitration) Amendment Rule 2017 contains transitional rules that form part of Schedule 4 of the NGR which describe the transitional arrangements in relation to the initial reporting of financial information and weighted average prices under Part 23. Under the transitional rules, initial reporting covers a six-month period which must be published in October 2018

that Jemena might have only included six months of revenue, expenses and return on capital in their calculation for 2018. Table 11 contrasts the revenue, operating expenses and return on capital for 2018 to the average of those in 2015 to 2017 for Jemena's pipelines. It appears that Jemena only reports revenue, operating expenses and return on capital for half a year in 2018.

Table 11
Jemena pipelines' RCM reporting in 2015 – 2017 vs. in 2018

	2015 - 2017			2018		
	Revenue	Opex	Return on capital	Revenue	Opex	Return on capital
	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions
	[A]	[B]	[C]	[D]	[E]	[F]
Darling Downs Pipeline	31.9	10.3	14.6	15.8	4.0	7.5
Eastern Gas Pipeline	151.7	22.1	65.1	71.6	15.6	28.5
Queensland Gas Pipeline	45.3	15.9	74.1	23.0	11.2	37.0
VicHub Pipeline	2.5	0.2	0.5	1.4	0.1	0.1

Sources: Part 23 financial information, October 2018, Table 4.1.
Notes:
[A]: The average revenue reported for the pipeline for the years 2015, 2016 and 2017.
[B]: The average operating expenses reported for the pipeline for the years 2015, 2016 and 2017.
[C]: The average return on capital reported for the pipeline for the years 2015, 2016 and 2017.
[D]: The revenue reported for the pipeline for the year 2018.
[E]: The operating expenses reported for the pipeline for the year 2018.
[F]: The return on capital reported for the pipeline for the year 2018.

131. Using the steps in Table 9 and Table 10, we estimate the return on capital for all fourteen pipelines. The estimated values for the last 5 years (up to and including 2018) are summarized in Table 12. Table 12 also provides a range of rates of return for fully regulated pipelines based on a sample of AER's and ERA's determinations over the same period.

or January 2019, depending on the service provider's reporting period. Following this first reporting period, service providers are required to report their financial information and weighted average price-information on an annual basis for every year thereafter.

Table 12
Rates of return calculated for all pipelines, 2014 to 2018

	2014	2015	2016	2017	2018
APA					
Berwyndale Wallumbilla Pipeline	9.11%	9.12%	9.07%	8.91%	8.88%
Goldfields Gas Pipeline	11.40%	9.31%	8.93%	9.08%	87.34%
Moomba to Sydney Pipeline	9.20%	9.20%	9.13%	9.03%	9.09%
South East South Australia Pipeline	9.12%	9.17%	9.08%	8.97%	8.93%
South West Queensland Pipeline	9.11%	10.07%	9.06%	8.91%	8.86%
Wallumbilla Gladstone Pipeline			8.99%	8.82%	8.76%
Jemena					
Darling Downs Pipeline	9.03%	8.70%	8.47%	7.99%	3.82%
Eastern Gas Pipeline	9.60%	7.41%	7.26%	7.22%	3.34%
Queensland Gas Pipeline	9.04%	8.68%	8.43%	7.81%	3.73%
VicHub Pipeline	7.89%	7.31%	6.97%	6.90%	3.21%
SEA Gas					
Port Campbell to Adelaide Pipeline	9.28%	8.25%	8.22%	6.89%	7.01%
Port Campbell to Iona Pipeline	9.15%	8.13%	8.10%	6.78%	6.90%
EPIC					
Moomba to Adelaide Pipeline System	8.57%	7.10%	7.07%	6.64%	8.17%
Palisade					
Tasmanian Gas Pipeline	0.47%	0.42%	0.35%	0.31%	0.30%
AER and ERA determinations					
Minimum	7.22%	5.73%	5.45%	5.45%	5.45%
Maximum	10.37%	9.76%	9.73%	7.31%	6.84%
Average	9.11%	7.54%	6.61%	6.34%	6.09%

Sources: Part 23 financial information, October 2018, Table 4.1; AER and ERA determinations (see Appendix A—Documents cited).
Notes:
Rate of return is calculated as the reported return on capital divided by the opening asset base calculated based on the information reported under the RCM.
The AER and ERA determination values are taken from determinations made between 2006 and 2018. For each determination we use the post-tax WACC in the first year of the regulatory period and assume that this WACC applies for the subsequent years in the regulatory period without accommodating changes in the return on debt.

132. Table 12 shows that in any given year, the rates of return across pipelines can differ from each other by 2% to 3%. In addition, other than the 2018 rates of return for Jemena pipelines, there are three sets of numbers in Table 12 that seem to be outliers relative to others.

    a. The inferred rates of return values for Tasmanian Gas Pipeline do not seem reliable. Palisade only reports a value of AUD 12 million of total assets for Tasmanian Gas Pipeline under the RCM, in contrast to more than AUD 300 million of construction or acquisition cost under the depreciated book value.[153] Also, we are unable to reconcile

[153] Tasmanian Gas Pipeline's Part 23 financial information, October 2018, Table 3.3.1.

the revenue, expenses and return on capital information that Palisade reports. For example, Palisade reports a total revenue of AUD 15.3 million under the "Statement of pipeline revenue and expenses" for the reporting period 1 January 2018 – 30 June 2018[154] but only AUD 34,151 for the year 2018 under the RCM. Palisade appears to have made two amendments to the AER Template that explain at least some of the inconsistencies in its reporting under the RCM.

i. First, where other service providers report in AUD, Palisade appears to report in thousands of AUD. If this is true, it means that Palisade is reporting AUD 34.1 million in revenue for 2018 rather than AUD 34,151, which is more comparable to a half-year revenue of AUD 15.3 million reported under "Statement of pipeline revenue and expenses" for the period 1 January 2018 – 30 June 2018.

ii. Second, Palisade appears to be reporting the closing asset value for each year (a cumulative value) in place of the annual change in asset value.

iii. Together, these imply that the closing asset value of the Tasmanian Gas Pipeline at 30 June 2018 is in fact AUD 934 million, rather than AUD 12 million (or AUD 12 billion). Adjusting our rate of return calculations for these assumed amendments[155] would result in much larger values for Tasmanian Gas Pipeline. Nonetheless, the adjusted rates for 2012 to 2018 would fall between 3.8% and 4.8%, which seems very small compared to other pipelines. Additionally, Palisade appears to report AUD 441 million (inputted as AUD 441 thousand) of construction costs under the RCM in its year of construction, 2002, but reports only 302.5 million of construction costs under the depreciated book value method. We do not attempt to "correct" the results for Palisade because we suspect that other corrections are required and because we want to use a consistent approach that produces mostly credible results for all other thirteen pipelines.

b. The rate of return for Goldfields Gas Pipeline in 2018 is much higher than all other rates (across pipelines and years). APA reports zero construction cost for the Goldfields Gas Pipeline (with AUD 220 million of total additions since construction). For 2018, APA reports a substantially larger return on capital component than in prior years, which results in a zero closing asset value under the RCM. APA's BoP does not explain this.

c. The rate of return for Wallumbilla Gladstone Pipeline in 2015 is approximately half of that in 2016 onwards. 2015 is the first year that APA reports information under the RCM for the Wallumbilla Gladstone Pipeline because it was built in 2014.

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[154] Tasmanian Gas Pipeline's Part 23 financial information, October 2018, Table 2.1.

[155] Tasmanian Gas Pipeline's Part 23 financial information from October 2018 does not include a record of the amendments made to the AER Template.

133. The RCM allows for losses (ie, when revenue from providing pipeline services does not exceed the sum of operating expenses, return on capital and tax liabilities) in one year to be added to the asset value in subsequent years. Certain pipeline owners report several years of losses since the construction of the pipeline, such that the asset value has been increasing through time (ie, cumulative depreciation since construction is negative). Table 13 reports the accumulated depreciation since construction across the fourteen Part 23 pipelines. A positive depreciation value in Table 13 means that the pipelines have depreciated over time, whereas a negative depreciation means that the pipelines have been making losses and therefore the asset value has increased over time. For example, in the case of Queensland Gas Pipeline (owned by Jemena), AUD 643 million of depreciation was added to the total construction cost and capital expenditure of AUD 368 million after 29 years, resulting in a closing asset value of more than AUD 1 billion as at 30 June 2018.

Table 13
Asset values under the RCM

	Construction cost in Table 4.1	Capex in Table 4.1	Negative residual value in Table 4.1	Disposal at cost in Table 4.1	Depreciation in Table 4.1	Closing asset value based on Table 4.1	Sum of capex and construction cost in Table 4.1
	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
APA							
Berwyndale Wallumbilla Pipeline	79.6	8.9	0.0	0.0	-7.7	96.1	88.4
Goldfields Gas Pipeline	0.0	237.9	0.0	-3.8	234.1	0.0	237.9
Moomba to Sydney Pipeline	859.3	550.2	0.0	-4.2	-678.2	2,083.6	1,409.5
South East South Australia Pipeline	20.1	3.7	0.0	0.0	-12.5	36.3	23.8
South West Queensland Pipeline	396.6	1,300.1	0.0	-2.9	-388.8	2,082.7	1,696.7
Wallumbilla Gladstone Pipeline	2,013.4	52.4	0.0	-4.9	624.2	1,436.7	2,065.8
Jemena							
Darling Downs Pipeline	180.6	39.6	2.7	0.0	28.9	194.0	220.2
Eastern Gas Pipeline	439.4	306.6	19.1	-1.9	-71.1	834.3	745.9
Queensland Gas Pipeline	135.9	232.2	7.0	0.0	-643.0	1,018.1	368.1
VicHub Pipeline	8.3	0.1	0.3	0.0	5.0	3.7	8.3
SEA Gas							
Port Campbell to Adelaide Pipeline	475.3	20.1	0.0	-0.6	88.4	406.4	495.4
Port Campbell to Iona Pipeline	9.3	9.7	0.0	0.0	5.2	13.8	19.0
EPIC							
Moomba to Adelaide Pipeline System	380.9	108.7	0.0	-0.1	-90.3	579.8	489.6
Palisade							
Tasmanian Gas Pipeline	12.4	0.1	0.0	0.0	-0.5	12.9	12.4

Sources: Part 23 financial information, October 2018, Table 4.1.
Notes:
[A]: The sum of all construction costs reported (across years) for the pipeline in Table 4.1.
[B]: The sum of capital expenditure (additions and capitalised maintenance) reported for the pipeline in Table 4.1.
[C]: The sum of negative residual value reported (across years) for the pipeline in Table 4.1.
[D]: The sum of direct and shared asset disposals reported (across years) for the pipeline in Table 4.1.
[E]: The sum of return of capital reported for the pipeline in Table 4.1. A positive value indicates that the pipeline's assets have depreciated since its construction.
[F]: The closing value of all assets at the end of reporting under the recovered capital method. [F] = [A] + [B] + [C] + [D] - [E].
[G] = [A] + [B]

134. The average annual depreciation rate under the RCM is reported in Table 14.

Table 14
Average annual depreciation under the RCM

	Depreciation in Table 4.1	First year of reporting in Table 4.1	Number of years of reporting in Table 4.1	Average annual depreciation	Sum of capex and construction cost in Table 4.1	Average annual depreciation as a % of [E]
	AUD millions		years	AUD millions	AUD millions	%
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	-7.7	2009	10	-0.8	88.4	-0.9%
Goldfields Gas Pipeline	234.1	2005	14	16.7	237.9	7.0%
Moomba to Sydney Pipeline	-678.2	2004	15	-45.2	1,409.5	-3.2%
South East South Australia Pipeline	-12.5	2005	14	-0.9	23.8	-3.7%
South West Queensland Pipeline	-388.8	1995	24	-16.2	1,696.7	-1.0%
Wallumbilla Gladstone Pipeline	624.2	2015	4	156.0	2,065.8	7.6%
Jemena						
Darling Downs Pipeline	28.9	2005	14	2.1	220.2	0.9%
Eastern Gas Pipeline	-71.1	1998	21	-3.4	745.9	-0.5%
Queensland Gas Pipeline	-643.0	1989	30	-21.4	368.1	-5.8%
VicHub Pipeline	5.0	2003	16	0.3	8.3	3.7%
SEA Gas						
Port Campbell to Adelaide Pipeline	88.4	2004	15	5.9	495.4	1.2%
Port Campbell to Iona Pipeline	5.2	2004	15	0.3	19.0	1.8%
EPIC						
Moomba to Adelaide Pipeline System	-90.3	2000	19	-4.8	489.6	-1.0%
Palisade						
Tasmanian Gas Pipeline	-0.5	2002	17	0.0	12.4	-0.2%

Sources: Part 23 financial information, October 2018, Table 4.1.
Notes:
[A]: The sum of return of capital reported for a pipeline in Table 4.1. A positive value indicates that the pipeline's assets have depreciated since its construction.
[B]: The first year for which construction costs are reported in Table 4.1.
[C]: The number of years between the first year of reporting in Table 4.1 and 2018.
[D] = [A] / [C], where a negative value indicates an annual increase in the pipeline's value through depreciation.
[E]: The sum of construction costs and capital expenditure (additions and capitalised maintenance) reported in Table 4.1.
[F]: [D] / [E] x 100

e. Recovered capital method versus depreciated book value method

135. Both the depreciated book value method and the RCM start with an initial asset value, and allow for subsequent additions and disposals to arrive at a current asset value. For the initial asset value, the AER Guideline allows service providers to use construction costs or acquisition cost in the depreciated book value method,[156] whereas only construction cost (or an estimated construction cost) is allowed under the RCM.[157] This means that the total investment amount reported by a pipeline is likely to be different between the depreciated book value method and the RCM.

156 AER Guideline, p. 12.

157 AER Guideline, pp. 18, 20-21.

136. Table 15 reports the construction cost (or acquisition cost) and subsequent cumulative capex for each pipeline under the depreciated book value method and the RCM. Note that under both methods, the construction or acquisition costs can be an accumulated figure over a number of years, as opposed to just the initial cost of construction or acquisition of the assets. The values in Table 15 under the depreciated book value method do not include "other non-depreciable assets", which includes goodwill for certain pipelines.

Table 15
Reporting under depreciated book value method versus reporting under the RCM

	Depreciated book value reporting			Recovered capital method reporting		
	Acquisition or construction year in Tables 3.1.1 and 3.3.1	Construction and acquisition costs based on Table 3.3	Accumulated capex based on Table 3.3	First year of reporting in Table 4.1	Construction cost in Table 4.1	Capex in Table 4.1
		AUD millions	AUD millions		AUD millions	AUD millions
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	2010	91.6	4.3	2009	79.6	8.9
Goldfields Gas Pipeline	2005	13.3	220.8	2005	0.0	237.9
Moomba to Sydney Pipeline	2000	803.9	400.3	2004	859.3	550.2
South East South Australia Pipeline	2007	18.0	1.9	2005	20.1	3.7
South West Queensland Pipeline	2012	1,374.2	402.1	1995	396.6	1,300.1
Wallumbilla Gladstone Pipeline	2015	2,599.1	10.3	2015	2,013.4	52.4
Jemena						
Darling Downs Pipeline	Various	356.9	18.2	2005	180.6	39.6
Eastern Gas Pipeline	Various	726.5	167.6	1998	439.4	306.6
Queensland Gas Pipeline	Various	160.8	210.1	1989	135.9	232.2
VicHub Pipeline	Various	9.2	0.0	2003	8.3	0.1
SEA Gas						
Port Campbell to Adelaide Pipeline	2004	475.3	20.1	2004	475.3	20.1
Port Campbell to Iona Pipeline	2004	9.3	9.7	2004	9.3	9.7
EPIC						
Moomba to Adelaide Pipeline System	2013	378.6	62.1	2000	380.9	108.7
Palisade						
Tasmanian Gas Pipeline	2002	302.5	0.0	2002	12.4	0.1

Sources: Part 23 financial information, October 2018, Tables 3.1.1, 3.3.1, 3.3.2 and 4.1.
Notes:
[A]: The pipeline acquisition year reported in Tables 3.1.1 and 3.3.1.
[B]: The sum of "Construction or acquisition cost" reported for each asset category in Tables 3.3.1 and 3.3.2.
[C]: The sum of "Additions" and "Capitalised maintenance" reported for each asset category in Tables 3.3.1 and 3.3.2.
[D]: The first year for which construction cost is reported in Table 4.1.
[E]: The sum of construction cost reported for direct and shared assets (across years) in Table 4.1.
[F]: The sum of additions and capitalised maintenance reported for direct and shared assets (across years) in Table 4.1.

137. The breakdown of construction or acquisition costs and additions (shown as capital expenditure in Table 15) serves to illustrate that the reporting of construction cost (or acquisition cost) is different between the depreciable book value method and the RCM, and is therefore not directly comparable. Except for SEA Gas, all service providers report different timings and/or value for their investment between the two methods. Table 15 also highlights the inconsistencies in the reporting of capital expenditure under the two methods. For example, for Moomba to Sydney Pipeline, APA reports AUD 400.3 million of capex between 2000 and 2018 under depreciated book value, but AUD 550.2 million between 2004 and 2018 under the RCM.

138. The current asset values derived from the RCM and the depreciated book value method are likely to be different for two main reasons. First, these methods are two different asset valuation frameworks: the depreciated book value method assumes straight-line depreciation, while under the RCM depreciation is the residual after subtracting operating expenses, net tax liabilities and allowed return on capital from revenue. Second, the initial asset value under the two methods can differ, as explained above. Table 16 reports the current asset value under the depreciated book value method and the RCM. For the sake of comparison, the asset value under the depreciated book value method in Table 16 does not include "other non-depreciable assets", which refers to goodwill for some pipelines. Further, since "other non-depreciable assets" presumably reflect the market value of pipeline capacity and our pricing benchmarks are cost-based, we also do not include "other non-depreciable assets" in subsequent calculations in this report.

Table 16
Current asset value as of 30 June 2018: depreciated book value method versus the RCM

	Depreciated book value method	RCM	RCM vs. depreciated book value method
	Total assets excluding other non-depreciable in Table 3.1	Closing asset value based on Table 4.1	Closing asset value in Table 4.1 as % of closing value in Table 3.1
	AUD millions	AUD millions	%
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	83.4	96.1	115.2%
Goldfields Gas Pipeline	190.7	0.0	0.0%
Moomba to Sydney Pipeline	961.9	2,083.6	216.6%
South East South Australia Pipeline	15.1	36.3	240.4%
South West Queensland Pipeline	1,623.1	2,082.7	128.3%
Wallumbilla Gladstone Pipeline	2,497.6	1,436.7	57.5%
Jemena			
Darling Downs Pipeline	469.8	194.0	41.3%
Eastern Gas Pipeline	969.8	834.3	86.0%
Queensland Gas Pipeline	450.7	1,018.1	225.9%
VicHub Pipeline	15.0	3.7	24.4%
SEA Gas			
Port Campbell to Adelaide Pipeline	397.0	406.4	102.4%
Port Campbell to Iona Pipeline	13.3	13.8	103.7%
EPIC			
Moomba to Adelaide Pipeline System	369.2	579.8	157.1%
Palisade			
Tasmanian Gas Pipeline	212.6	12.9	6.1%

Sources: Part 23 financial information, October 2018, Tables 3.1 and 4.1.
Notes:
[A]: Closing asset value under the depreciated book value method, excluding non-depreciable assets.
[B]: Closing asset value under the recovered capital method.
[C] = [B] / [A] x 100

139. Table 16 shows that the current asset value under the RCM can be more than twice that under the depreciated book value method, for example, in the case of Queensland Gas Pipeline and Moomba to Sydney Pipeline. For both of these pipelines, the total value of depreciation under the RCM has been positive (ie, the asset value has been increasing over time), resulting in a large difference when compared to the depreciated book value method.

140. The RCM results in smaller current asset value for some pipelines, such as Darling Downs Pipeline and Wallumbilla Gladstone Pipeline. One reason for this may be that the original asset value (construction or acquisition cost) reported under the depreciated book value (eg, AUD 356.9 million for Darling Downs Pipeline) is larger than the construction cost reported under the RCM (AUD 180.6 million for Darling Downs Pipeline) (see Table 15). In the case of Wallumbilla Gladstone Pipeline, as explained above, we would assume that the

construction cost reported under the RCM does not include capitalisation of long-term transportation contracts that were acquired at the same time as the pipeline was acquired (see paragraph 116).[158] Under the RCM, the revenue generated from these contracts appears to be used to "depreciate" the construction cost, which does not include the capitalised value of these same contracts. As a result, the RCM value appears to be depreciating faster than the book value.

3. Expenses

141. Within Part 23 financial information, service providers are required to report operating expenses on an annual basis since the construction of the pipeline under the RCM.[159] In addition, for the reporting period 1 January 2018 – 30 June 2018, service providers are required to report detailed expenses items (eg, repair and maintenance, wages etc.) under the "Statement of revenue and expenses" (Table 2.1 of the AER Template). Table 17 summarises and compares (i) the operating expenses reported under the RCM for 2015 – 2017 and (ii) the expenses reported under the "Statement of revenue and expenses" (excluding depreciation). Table 17 shows that (i) for some pipelines the operating expenses reported under the RCM are not comparable (ie, might not convey the same information) to that reported under the statement of revenue and expenses and/or (ii) operating expenses varies significantly over time.

142. For example, Wallumbilla Gladstone Pipeline reports total expenses (excluding depreciation) of 107 million AUD in Table 2.1 for the period 1 January 2018 to 30 June 2018, while its six-month operating expenses in Table 4.1 averaged over 2015, 2016 and 2017 is approximately 15 million AUD. A closer look shows that the total expenses of 107 million AUD include 92.6 million AUD of "Other direct costs".[160] Excluding "Other direct costs" leaves 14.4 million AUD in expenses. This suggests that in the case of Wallumbilla Gladstone Pipeline, Tables 2.1 and 4.1 might convey different sets of cost information. Another example of differences between current expenses reported in Table 2.1 and historical operating expenses reported in Table 4.1 is in the case of Tasmanian Gas Pipeline. As explained above (paragraph 133), we do not understand why historical information on revenue and expenses for Tasmanian Gas Pipeline appears different to that for the reporting period 1 January 2018 – 30 June 2018.

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158 APA's FY2015 financial report indicates that it acquired Wallumbilla Gladstone Pipeline for approximately AUD 5.9 billion, with the amount of "contract and other intangibles" increasing from AUD 677 million to AUD 3.4 billion due to acquisitions/additions. See APA Group Annual Report for the financial year ended 30 June 2015, pp. 16, 74.

159 AER Guideline, p. 19.

160 As noted above, APA states that "[t]he reported operating expenditure in the Statement of Pipeline Revenue and Expenses are inclusive of adjustments so that those costs are equivalent to those of a firm operating a business of a size and complexity of the non-scheme pipeline in the context of a workably competitive market. The adjustments have been reported in "Other direct costs"". It is unclear whether "Other direct costs' includes other items besides this adjustment. APA Basis of Preparation, p. 9.

Table 17
Expenses 1 January 2018 – 30 June 2018 versus historical expenses reported in the RCM

		Opex in Table 4.1				
	Total costs less depreciation in Table 2.1	2015	2016	2017	Average half-year opex (2015-2017)	Ratio of average half-year opex to total costs less depreciation
	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	%
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	1.5	2.8	2.4	3.0	1.4	90.1%
Goldfields Gas Pipeline	4.7	3.2	7.4	8.4	3.1	66.9%
Moomba to Sydney Pipeline	11.6	26.7	30.4	32.9	14.8	127.1%
South East South Australia Pipeline	0.4	0.4	0.7	0.9	0.3	79.9%
South West Queensland Pipeline	15.8	32.2	34.9	30.2	16.0	101.0%
Wallumbilla Gladstone Pipeline	107.0	6.8	42.2	41.4	14.9	13.9%
Jemena						
Darling Downs Pipeline	4.0	10.0	10.3	10.5	5.1	126.5%
Eastern Gas Pipeline	15.8	21.0	21.5	23.8	10.9	69.0%
Queensland Gas Pipeline	11.6	16.2	15.9	15.6	7.9	67.6%
VicHub Pipeline	0.1	0.2	0.2	0.2	0.1	94.5%
SEA Gas						
Port Campbell to Adelaide Pipeline	8.0	10.2	11.0	13.1	5.6	70.2%
Port Campbell to Iona Pipeline	0.2	0.5	0.5	0.6	0.3	112.0%
EPIC						
Moomba to Adelaide Pipeline System	13.6	21.1	25.3	24.3	11.6	85.4%
Palisade						
Tasmanian Gas Pipeline	5.8	0.0	0.0	0.0	0.0	0.1%

Sources: Part 23 financial information, October 2018, Tables 2.1 and 4.1.
Notes:
[A]: The sum of all costs reported in Table 2.1 except depreciation.
[B]: Operating expenses reporting within "return of capital" in Table 4.1 for the year 2015.
[C]: Operating expenses reporting within "return of capital" in Table 4.1 for the year 2016.
[D]: Operating expenses reporting within "return of capital" in Table 4.1 for the year 2017.
[B]-[D]: Note that some pipelines report by calendar and others by fiscal year.
[E] = ([B] + [C] + [D]) / 3 x 180 / 365
[F] = [E] / [A] x 100

143. Table 18 reports a breakdown of total expenses for the period 1 January 2018 to 30 June 2018 into shared and direct costs. The BoP indicates that different service providers use different allocation methods to allocate shared costs, with APA not undertaking an explicit allocation of shared support costs. This means the magnitude of shared costs reported for each pipeline depends on the methods of allocation the service providers use. Further, shared costs and direct costs across different service providers might not necessarily refer to similar cost items. For example, APA includes "adjustments" in its direct costs (through a category within direct costs called "other direct costs") so that its operating expenses are "equivalent to those of a firm operating a business of a size and complexity of the non-scheme pipeline in the context of a workably competitive market".[161] Further, some of APA's direct costs also include what

[161] APA Basis of Preparation, p. 9.

appears to be shared costs (ie, "other attributable costs", see paragraph 86. Table 18 shows that shared costs account for a relatively large proportion of total costs for most pipelines (20% - 80% for ten out of the fourteen pipelines).

Table 18
Direct vs. shared cost
1 January 2018 – 30 June 2018

	Direct costs less depreciation in Table 2.1	Shared costs less depreciation in Table 2.1	Total costs less depreciation in Table 2.1	Shared costs as % of total costs in Table 2.1
	AUD millions	AUD millions	AUD millions	%
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	0.7	0.8	1.5	50.9%
Goldfields Gas Pipeline	2.6	2.1	4.7	44.6%
Moomba to Sydney Pipeline	6.7	5.0	11.6	42.8%
South East South Australia Pipeline	0.1	0.3	0.4	63.6%
South West Queensland Pipeline	8.7	7.1	15.8	45.1%
Wallumbilla Gladstone Pipeline	95.0	12.0	107.0	11.2%
Jemena				
Darling Downs Pipeline	2.3	1.7	4.0	41.8%
Eastern Gas Pipeline	9.1	6.7	15.8	42.4%
Queensland Gas Pipeline	8.5	3.1	11.6	27.0%
VicHub Pipeline	0.1	0.0	0.1	0.0%
SEA Gas				
Port Campbell to Adelaide Pipeline	6.0	2.0	8.0	24.6%
Port Campbell to Iona Pipeline	0.2	0.0	0.2	12.4%
EPIC				
Moomba to Adelaide Pipeline System	2.8	10.8	13.6	79.5%
Palisade				
Tasmanian Gas Pipeline	5.8	0.0	5.8	0.0%

Sources: Part 23 financial information, October 2018, Table 2.1.
Notes:
[A]: The sum of all cost items except depreciation reported under "Direct costs" in Table 2.1.
[B]: The sum of all cost items reported except depreciation under "Shared costs" in Table 2.1.
[C] = [A] + [B]
[D] = [B] / [C] x 100

144. Shared costs in the AER Template include "Employee costs", "Information technology and communication costs", "Indirect operating expenses", "Shared asset depreciation", "Rental and leasing costs", "Borrowing costs", "Loss from sale of shared fixed assets", "Impairment losses" and "Other shared costs".[162] Table 19 reports the two largest shared cost items across

[162] AER Template, "2. Revenue and expenses".

pipelines.[163] For non-APA pipelines, employee costs are the biggest component of shared costs. APA does not report individual shared cost components but instead reports all shared costs under "other shared costs", which, according to APA's BoP, consist of corporate costs attributable to the service provider.[164]

Table 19
Breakdown of shared cost
1 January 2018 – 30 June 2018

		Largest shared cost items as % of total costs in Table 2.1	
	Shared costs as % of total costs in Table 2.1	Shared employee costs in Table 2.1	Other shared costs in Table 2.1
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	50.9%	0.0%	50.9%
Goldfields Gas Pipeline	44.6%	0.0%	44.6%
Moomba to Sydney Pipeline	42.8%	0.0%	42.8%
South East South Australia Pipeline	63.6%	0.0%	63.6%
South West Queensland Pipeline	45.1%	0.0%	45.1%
Wallumbilla Gladstone Pipeline	11.2%	0.0%	11.2%
Jemena			
Darling Downs Pipeline	41.8%	32.8%	0.0%
Eastern Gas Pipeline	42.4%	28.8%	0.0%
Queensland Gas Pipeline	27.0%	18.3%	0.0%
VicHub Pipeline	0.0%	0.0%	0.0%
SEA Gas			
Port Campbell to Adelaide Pipeline	24.6%	17.6%	0.0%
Port Campbell to Iona Pipeline	12.4%	4.1%	0.0%
EPIC			
Moomba to Adelaide Pipeline System	79.5%	60.5%	13.5%
Palisade			
Tasmanian Gas Pipeline	0.0%	0.0%	0.0%

Sources: Part 23 financial information, October 2018, Table 2.1.
Notes:
[A]: All shared cost items reported in Table 2.1 (except depreciation) as a percentage of total costs less depreciation.
[B]: "Employee costs" reported in Table 2.1 as a percentage of total costs less depreciation.
[C]: "Other shared costs" as a percentage of total costs less depreciation.

145. Direct costs within the AER Template include "Repairs and maintenance", "Wages", "Depreciation", "Insurance", "Licence and regulatory costs", "Directly attributable finance charges", "Leasing and rental costs", and "Other direct costs".[165] Table 20 summarises the

[163] For each of the pipelines, either "Employee costs' or "Other shared costs' is the largest component within shared costs.

[164] APA Basis of Preparation, p. 10.

[165] AER Template, "2. Revenues and expenses".

largest direct cost components across pipelines. For many pipelines, wages are the largest direct cost component (ranging from 20 to 100 percent of direct costs). Repairs and maintenance is SEA Gas' largest direct cost component. APA reports a large amount of "other direct costs" for many pipelines. APA states that "other direct costs" include "adjustments so that [operating expenditure is] equivalent to those of a firm operating a business of a size and complexity of the non-scheme pipeline in the context of a workably competitive market".[166]

Table 20
Breakdown of direct costs
1 January 2018 – 30 June 2018

		Largest direct cost items as % of total costs in Table 2.1		
	Direct costs less depreciation in Table 2.1	Wages in Table 2.1	Repairs and maintenance in Table 2.1	Other direct costs in Table 2.1
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	49.1%	31.9%	0.0%	16.0%
Goldfields Gas Pipeline	55.4%	0.0%	0.0%	53.1%
Moomba to Sydney Pipeline	57.2%	47.6%	0.8%	3.5%
South East South Australia Pipeline	36.4%	15.5%	0.0%	16.6%
South West Queensland Pipeline	54.9%	36.8%	0.0%	15.3%
Wallumbilla Gladstone Pipeline	88.8%	0.4%	0.0%	86.5%
Jemena				
Darling Downs Pipeline	58.2%	27.6%	5.3%	20.4%
Eastern Gas Pipeline	57.6%	28.1%	10.6%	16.2%
Queensland Gas Pipeline	73.0%	38.3%	16.3%	14.8%
VicHub Pipeline	100.0%	100.0%	0.0%	0.0%
SEA Gas				
Port Campbell to Adelaide Pipeline	75.4%	19.3%	45.2%	7.3%
Port Campbell to Iona Pipeline	87.6%	22.9%	54.1%	7.4%
EPIC				
Moomba to Adelaide Pipeline System	20.5%	0.0%	18.4%	0.9%
Palisade				
Tasmanian Gas Pipeline	100.0%	0.0%	4.9%	85.2%

Sources: Part 23 financial information, October 2018, Table 2.1.
Notes:
[A]: The sum of all direct cost items reported in Table 2.1, except depreciation on direct assets, as a percentage of total costs less depreciation on all assets.
[B]: "Wages" reported in Table 2.1 as a percentage of total costs less depreciation on all assets.
[C]: "Repairs and maintenance" reported in Table 2.1 as a percentage of total costs less depreciation on all assets.
[D]: "Other direct costs" reported in Table 2.1 as a percentage of total costs less depreciation on all assets.

166 APA Basis of Preparation, p. 9.

4. Revenue

146. Service providers report revenue for the reporting period 1 January 2018 – 30 June 2018 as part of the Part 23 financial information under "Statement of revenue and expenses" and as part of the weighted average price (WAP) reporting (in Table 5.1 of the AER Template). In addition, service providers are required to report historical revenue for each year following a pipeline's construction under the RCM.

147. As part of the "Statement of revenue and expenses" (Table 2.1 of the AER Template), service providers report revenue for the period 1 January 2018 – 30 June 2018. "Total revenue" in Table 2.1 comprises of "Total direct revenue" and "Total indirect revenue allocated". "Total direct revenue" comprises of "Total service revenue" and "Other direct revenue". The AER Template also includes Table 2.1.1 ("Revenue by service") in which "Total direct revenue" is categorised into different services (such as firm forward haul transportation services or backhaul services and other services), "Customer contribution revenue", "Profit from sale of fixed assets" and "Other direct revenue".

148. Using the breakdown in Table 2.1.1, we identify the two largest sources of revenue for each pipeline, summarised in Table 21. All pipelines generate a majority of their revenue from firm forward haul transportation. The second largest source of revenue varies across pipelines. For example, Moomba to Sydney Pipeline and Tasmanian Gas Pipeline generate more than 10% of total revenue from park and park and loan services. South West Queensland Pipeline generates more than 20% of total revenue from firm stand-alone compression service. Three Jemena pipelines (Eastern Gas Pipeline, Queensland Gas Pipeline and VicHub Pipeline), one APA pipeline (South East South Australia Pipeline) and the two SEA Gas pipelines report their second largest source of total revenue as "Other direct revenue". Jemena explains in its BoP that "[t]hese are revenue items that are not pipeline service related and is miscellaneous in nature".[167] SEA Gas does not define "Other direct revenue" in its BoP.

[167] See, for example, Jemena Basis of Preparation – Queensland Gas Pipeline, p. 10.

Table 21
The largest sources of revenue as a % of total revenue
1 January 2018 – 30 June 2018

	Firm forward haul transportation revenue in Table 2.1.1	Revenue from second largest source of revenue	Second largest source of revenue
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	99.5%	0.4%	Interruptible or as available transportation
Goldfields Gas Pipeline	94.6%	4.2%	Interruptible or as available transportation
Moomba to Sydney Pipeline	87.2%	11.5%	Park/park and loan
South East South Australia Pipeline	99.2%	0.8%	Other direct
South West Queensland Pipeline	71.9%	23.5%	Firm stand alone compression
Wallumbilla Gladstone Pipeline	100.0%	0.0%	Park/park and loan
Jemena			
Darling Downs Pipeline	89.6%	9.5%	Interruptible or as available transportation
Eastern Gas Pipeline	81.8%	8.9%	Other direct
Queensland Gas Pipeline	93.7%	3.7%	Other direct
VicHub Pipeline	90.9%	5.2%	Other direct
SEA Gas			
Port Campbell to Adelaide Pipeline	96.1%	3.1%	Other direct
Port Campbell to Iona Pipeline	71.9%	27.3%	Other direct
EPIC			
Moomba to Adelaide Pipeline System	90.9%	5.6%	Park/park and loan
Palisade			
Tasmanian Gas Pipeline	83.0%	12.6%	Park/park and loan

Sources: Part 23 financial information, October 2018, Table 2.1.1.
Notes:
[A]: Firm forward haul transportation revenue as a percentage of total revenue reported in Table 2.1.
[B]: The revenue from the second largest source of direct revenue as a percentage of total revenue reported in Table 2.1.
[C]: The name of the second largest source of revenue reported (as a percentage) in column [B].

149. In Table 22, we calculate for each pipeline the revenue generated from all pipeline services included in Table 2.1.1 of the AER Template, excluding "Distribution/transmission revenue",[168] "Customer contribution revenue", "Profit from sale of fixed assets" and "Other direct revenue", and compare this calculated total service revenue to "Total direct revenue" and "Total revenue" reported in Table 2.1 of the AER Template. Our estimated total service revenue accounts for more than 90% of total revenue for all pipelines, except in the case of Port Campbell to Iona, where "Other direct revenue" accounts for a large proportion of total revenue, as shown in Table 21. Table 22 also shows that "Total direct revenue" accounts for almost all of total revenue for all pipelines.

[168] We do not know what this line item is intended to capture. It is zero for all of the pipelines discussed in this report.

Table 22
Comparison of revenues reported in Table 2.1 and Table 2.1.1
1 January 2018 – 30 June 2018

	Total service revenue based on Table 2.1.1	Direct revenue in Table 2.1	Total revenue in Table 2.1	Total service revenue as a % of total revenue	Direct revenue as a % of total revenue
	AUD millions	AUD millions	AUD millions	%	%
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	6.8	6.8	6.8	100.0%	100.0%
Goldfields Gas Pipeline	31.9	32.1	32.1	99.3%	100.0%
Moomba to Sydney Pipeline	69.3	69.9	69.9	99.2%	100.0%
South East South Australia Pipeline	1.2	1.2	1.2	99.2%	100.0%
South West Queensland Pipeline	123.8	128.9	128.9	96.0%	100.0%
Wallumbilla Gladstone Pipeline	260.3	260.3	260.3	100.0%	100.0%
Jemena					
Darling Downs Pipeline	15.6	15.8	15.8	99.1%	100.0%
Eastern Gas Pipeline	65.2	71.6	71.6	91.1%	100.0%
Queensland Gas Pipeline	22.4	23.4	23.4	95.6%	100.0%
VicHub Pipeline	1.3	1.4	1.4	94.8%	100.0%
SEA Gas					
Port Campbell to Adelaide Pipeline	35.3	36.5	36.7	96.1%	99.2%
Port Campbell to Iona Pipeline	0.9	1.3	1.3	71.9%	99.2%
EPIC					
Moomba to Adelaide Pipeline System	37.2	37.3	37.3	99.6%	100.0%
Palisade					
Tasmanian Gas Pipeline	14.8	15.3	15.3	96.8%	100.0%

Sources: Part 23 financial information, October 2018, Tables 2.1 and 2.1.1.
Notes:
[A]: The sum of revenues reported in Table 2.1.1 for "[f]irm forward haul transportation services", "[i]nterruptible or as available transportation services", "[b]ackhaul services", "[f]irm stand-alone compression services", "[i]nterruptible or as available stand-alone compression service", "[p]ark and loan services", "[c]apacity trading service", and "[i]n pipe trading service".
[B]: Direct revenue reported in Table 2.1.
[C]: Total revenue reported in Table 2.1.
[D] = [A] / [C] x 100
[E] = [B] / [C] x 100

150. Service providers are also required to report revenue in their calculations of the WAP. Service providers are required to report a WAP for each service a pipeline provides, except where a service is exempt. An exempt service is one that was provided to no more than two users during the reporting period.[169] Table 23 summarises the total service revenue[170] and exempt service revenue reported in the WAP reporting (Table 5.1 of the AER Template). For comparison, Table 23 also summarises the total service revenue calculated from Table 2.1.1

[169] National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 556(3).

[170] Including revenue from transportation services, stand-alone compression services, and storage services in Table 5.1 of the AER Template.

of the AER Template.[171] Table 23 shows that exempt services account for the majority of revenue reported by Berwyndale Wallumbilla Pipeline, South East South Australia Pipeline, Darling Downs Pipeline and Port Campbell to Iona Pipeline. Tasmania Gas Pipeline reports zero exempt revenue in Table 5.1. However, a comparison between the service revenue reported in Table 5.1 and Table 2.1.1 shows that more than 50 percent of Tasmania Gas Pipeline's revenue is not reported (ie, exempt) in the calculation of WAP. In contrast, Eastern Gas Pipeline appears to exclude exempt revenue from its reporting in Table 2.1.1.

[171] Note that Table 2.1 has a line item for "Total service revenue". However, in the AER Template this item includes non-service revenue items such as "Customer contribution revenue", "Profit from sales of fixed assets", and "Other direct revenue" from Table 2.1.1. The "Total service revenue based on Table 2.1.1" we calculate in Table 23 does not include these items, as well as "Distribution/transmission revenue", and therefore is not identical to "Total service revenue" in Table 2.1 of the AER Template. We do not know what "Distribution/transmission revenue" is intended to capture. It is zero for all of the pipelines discussed in this report.

Table 23
Comparison of revenues reported in Table 2.1.1 and Table 5.1
1 January 2018–30 June 2018

	Total service revenue based on Table 2.1.1	Total service revenue based on Table 5.1	Exempt service revenue in Table 5.1	Exempt revenue as % of service revenue	Does reported service revenue differ (Y/N)?
	AUD millions	AUD millions	AUD millions	%	
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	6.8	6.8	6.8	99.6%	No
Goldfields Gas Pipeline	31.9	31.8	0.1	0.2%	No
Moomba to Sydney Pipeline	69.3	69.2	0.0	0.0%	No
South East South Australia Pipeline	1.2	1.2	1.2	100.0%	No
South West Queensland Pipeline	123.8	123.0	3.1	2.6%	No
Wallumbilla Gladstone Pipeline	260.3	260.3	0.0	0.0%	No
Jemena					
Darling Downs Pipeline	15.6	15.6	15.6	100.0%	No
Eastern Gas Pipeline	65.2	67.5	2.3	3.4%	Yes
Queensland Gas Pipeline	22.4	22.4	0.0	0.0%	No
VicHub Pipeline	1.3	1.3	0.0	1.6%	No
SEA Gas					
Port Campbell to Adelaide Pipeline	35.3	35.3	0.0	0.0%	No
Port Campbell to Iona Pipeline	0.9	0.0	0.0	100.0%	Yes
EPIC					
Moomba to Adelaide Pipeline System	37.2	37.2	0.0	0.0%	No
Palisade					
Tasmanian Gas Pipeline	14.8	6.5	0.0	56.2%	Yes

Sources: Part 23 financial information, October 2018, Tables 2.1.1 and 5.1.
Notes:
[A]: The sum of revenues reported in Table 2.1.1 for "firm forward haul transportation services", "interruptible or as available transportation services", "backhaul services", "firm stand-alone compression services", "interruptible or as available stand-alone compression service", "park and loan services", "capacity trading service", and "in pipe trading service".
[B]: The sum of revenues from all services, including exempt services, reported in Table 5.1.
[C]: Exempt service revenue reported in Table 5.1.
[D] = [C] / [B] x 100 for all pipelines except Port Campbell to Iona and Tasmanian Gas pipelines. For Port Campbell to Iona and Tasmanian Gas pipelines [D] = ([A] - [B]) / [A] x 100. In the case of the exceptions, these pipelines report zero exempt service revenue in Table 5.1, but also report higher total service revenue in Table 2.1 than in Table 5.1.
[E]: "Yes" if the absolute difference between [A] and [B] is greater than 2% of [A] and otherwise no.

5. Weighted average price

151. Table 24 reports the WAP for the largest reported revenue item for each pipeline. The AER Template requires that revenue and quantity be reported for each combination of service type (such as firm transport or standalone firm compression), charging method (such as postage stamp or zonal) and charging basis, which can be in terms of capacity (reserved MDQ over the contracted period) or in terms of volume (actual throughput). The largest revenue item is the combination with the largest revenue. In other words, it is the largest revenue item for which a single WAP can be identified in Table 5.1 of the AER Template. We refer to the service corresponding to this revenue item as the "main service" in the remainder of this report.

Table 24
Weighted average price associated with the largest disclosed revenue item
1 January 2018 – 30 June 2018

	Main service based on Table 5.1	Revenue of main service in Table 5.1	Quantity sold of main service	Weighted average price
		AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	Interruptible or as available transport			
Goldfields Gas Pipeline	Firm forward haul transport	22.4	12,992.7	1.72
Moomba to Sydney Pipeline	Firm forward haul transport	34.0	42,264.2	0.80
South East South Australia Pipeline	Not disclosed in Table 5.1			
South West Queensland Pipeline	Firm forward haul transport	89.5	94,891.3	0.94
Wallumbilla Gladstone Pipeline	Firm forward haul transport	260.3	273,310.0	0.95
Jemena				
Darling Downs Pipeline	Not disclosed in Table 5.1			
Eastern Gas Pipeline	Firm forward haul transport	56.5	48,815.7	1.16
Queensland Gas Pipeline	Firm forward haul transport	22.0	25,482.2	0.86
VicHub Pipeline	Firm forward haul transport	1.2	17,195.0	0.07
SEA Gas				
Port Campbell to Adelaide Pipeline	Firm forward haul transport	35.3	56,520.0	0.62
Port Campbell to Iona Pipeline	Not disclosed in Table 5.1			
EPIC				
Moomba to Adelaide Pipeline System	Firm forward haul transport	23.8	30,103.0	0.79
Palisade				
Tasmanian Gas Pipeline	Firm forward haul transport	6.5	3,351.2	1.93

Sources: Part 23 financial information, October 2018, Table 5.1.
Notes:
Berwyndale Wallumbilla Pipeline's revenue is mostly exempt from weighted average price reporting. Its main service in the current reporting period was interruptible or as available transportation service charged on a postage stamp basis, for which it reported approximately AUD 30 thousand in revenue and 150 TJ of throughput, resulting in a weighted average price of AUD 0.20 per GJ of throughput for the period 1 January 2018 – 30 June 2018. Port Campbell to Iona Pipeline services two customers and it therefore exempt from WAP reporting (see SEA Gas Basis of Preparation, p. 8).[A]: The service associated with the largest revenue item disclosed in Table 5.1. Revenue items are defined as combinations of service type and charging method. An example of a revenue item might be "firm forward haul transportation between receipt point A and delivery point B charged on a capacity basis".
[B]: The revenue associated with the largest revenue item disclosed in Table 5.1.
[C]: The quantity sold associated with the largest revenue item disclosed in Table 5.1.
[D] = ([B] x 1,000,000) / ([C] x 1,000)

152. Table 25 reports the proportion of revenue of the main revenue service in Table 24 relative to total service revenue and total revenue, respectively. The main revenue service accounts for more than 70% of total service revenue for seven out of the fourteen pipelines. For three pipelines (South East South Australia Pipeline, Darling Downs Pipeline, and Port Campbell to Iona Pipeline), 100% of service revenue is exempt, as shown in Table 23, and therefore no WAP is reported. Four other pipelines where main service revenue accounts for less than 70% of total service revenue are Moomba to Sydney Pipeline, Moomba to Adelaide Pipeline System, Berwyndale Wallumbilla Pipeline and Tasmanian Gas Pipeline. Berwyndale Wallumbilla Pipeline and Tasmanian Gas Pipeline have a significant amount of exempt

revenue for the reporting period 1 January 2018 to 30 June 2018. Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline System use multiple charging methods. Each method is reported under a separate item in the WAP reporting. Moomba to Sydney Pipeline records a separate revenue item for "firm capacity" that is charged per day per GJ of MDQ per kilometre (as opposed to being charged per day per GJ of MDQ), which comprises 38.5% of total service revenue. Moomba to Adelaide Pipeline System similarly has a separate revenue item for firm forward haul transportation charged on a volumetric basis, which comprises 27.2% of total service revenue. We are unable to reconcile revenue from different charging methods to fit a single "WAP per day per GJ of MDQ".[172]

[172] The ACCC recently published its review of the WAP reported by non-scheme pipelines and concluded that the WAP "do not provide a good representation of the prices paid by individual shippers" and "are not always comparable to standing prices". The ACCC obtained information on the calculations of the WAP, including "intermediary calculations and individual shipper information". The ACCC identified several limitations and issues with the reported WAP, including, "the aggregation of prices ignoring the fact that the underlying non-price terms and conditions associated with a service may differ substantially between individual contracts", "some apparent errors in published WAPs", "the delineation between volumetric and capacity components of WAPs creating difficulties in comparing published WAPs to standing offers", "the calculation of WAPs being open to manipulation by pipeline operators", and "the exemption framework resulting in WAPs not being published for all services (ie, if there are two or less users of the service)". See ACCC, "Adequacy of weighted average price information – ACCC recommendations", 2019, p. 3.

Table 25
Main service revenue relative to total service revenue and total pipeline revenue

	Revenue of main service in Table 5.1	Total service revenue based on Table 2.1.1	Total revenue in Table 2.1	Main service revenue as a % of total service revenue	Main service revenue as a % of total revenue
	AUD millions	AUD millions	AUD millions	%	%
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	0.0	6.8	6.8	0.4%	0.4%
Goldfields Gas Pipeline	22.4	31.9	32.1	70.1%	69.6%
Moomba to Sydney Pipeline	34.0	69.3	69.9	49.0%	48.6%
South East South Australia Pipeline		1.2	1.2		
South West Queensland Pipeline	89.5	123.8	128.9	72.3%	69.4%
Wallumbilla Gladstone Pipeline	260.3	260.3	260.3	100.0%	100.0%
Jemena					
Darling Downs Pipeline		15.6	15.8		
Eastern Gas Pipeline	56.5	65.2	71.6	86.6%	78.8%
Queensland Gas Pipeline	22.0	22.4	23.4	98.1%	93.7%
VicHub Pipeline	1.2	1.3	1.4	95.9%	90.9%
SEA Gas					
Port Campbell to Adelaide Pipeline	35.3	35.3	36.7	100.0%	96.1%
Port Campbell to Iona Pipeline		0.9	1.3		
EPIC					
Moomba to Adelaide Pipeline System	23.8	37.2	37.3	64.0%	63.7%
Palisade					
Tasmanian Gas Pipeline	6.5	14.8	15.3	43.8%	42.4%

Sources: Part 23 financial information, October 2018, Tables 2.1, 2.1.1 and 5.1.
Notes:
Berwyndale Wallumbilla Pipeline's revenue is mostly exempt from weighted average price reporting. It reported approximately AUD 30 thousand in main service revenue for the period 1 January 2018 – 30 June 2018. Port Campbell to Iona Pipeline services two customers and it therefore exempt from WAP reporting (see SEA Gas Basis of Preparation, p. 8).
[A]: The revenue of the largest revenue item reported in Table 5.1. Revenue items are defined as combinations of service type and charging method. An example of a revenue item might be "firm forward haul transportation between receipt point A and delivery point B charged on a capacity basis".
[B]: The sum of revenues reported in Table 2.1.1 for "firm forward haul transportation services", "interruptible or as available transportation services", "backhaul services", "firm stand-alone compression services", "interruptible or as available stand-alone compression service", "park and loan services", "capacity trading service", and "in pipe trading service".
[C]: Total revenue reported in Table 2.1.
[D] = [A] / [B] x 100
[E] = [A] / [C] x 100

6. Related party transactions

153. The AER Template requires service providers to report revenue and expenses with and without related party transactions. For our summary statistics in previous sections and for the calculation of pricing benchmarks, we use the reported values that include related party transactions. Table 26 summarises the revenue and expenses with and without related party transactions, reported in the "Statement of revenue and expenses", for each pipeline. Only three pipelines have revenue from related party transactions, which accounts for a small proportion of total revenue (less than 1%). In contrast, six pipelines (Jemena and SEA Gas

pipelines) report a large amount of expenses from related party transactions. In particular, almost all of Jemena's expenses come from related party transactions. For SEA Gas, expenses in connection with related party transactions account for more than 25% of total expenses. SEA Gas and Jemena provide an explanation of their related party transactions in their BoP.[173] In our summary tables above, as well in our calculations of pricing benchmarks in the next section, we use the reported figures that include related party transactions.

[173] SEA Gas states "[t]he Statement of Expenses includes Related Party expenses. The SEA Gas Partnership contracts with APA Group (a 50% owner of the SEA Gas Partnership) for the provision of maintenance services and for the procurement of some insurance. All operational and other business activities are performed by SEA Gas personnel." (SEA Gas Basis of Preparation, p. 6). For Darling Downs Pipeline, Jemena explains that "The majority of costs that DDP incurs are sourced from a related entity, Jemena Asset Management Pty Ltd (JAM), which is part of the Jemena Group. JAM records costs that are attributable to DDP and uses SAP functionality to transfer such costs at zero margin to DDP." (Jemena Basis of Preparation – Darling Downs Pipeline, p. 5.) A similar explanation was provided for Eastern Gas Pipeline, Queensland Gas Pipeline and VicHub Pipeline. (Jemena Basis of Preparation – Eastern Gas Pipeline, p. 5; Jemena Basis of Preparation – Queensland Gas Pipeline, p. 5; Jemena Basis of Preparation – VicHub Pipeline, p. 5.)

Table 26
Comparison of revenues and expenses when excluding or including related party transactions

	Revenue in Table 2.1 excluding related party transactions	Revenue in Table 2.1 including related party transactions	Total costs less depreciation in Table 2.1 excluding related party transactions	Total costs less depreciation in Table 2.1 including related party transactions	Revenue excluding related party transactions over total revenue	Expenses excluding related party transactions over total expenses
	AUD millions	AUD millions	AUD millions	AUD millions	%	%
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	6.8	6.8	1.5	1.5	100.0%	100.0%
Goldfields Gas Pipeline	32.1	32.1	4.7	4.7	100.0%	100.0%
Moomba to Sydney Pipeline	69.9	69.9	11.6	11.6	100.0%	100.0%
South East South Australia Pipeline	1.2	1.2	0.4	0.4	100.0%	100.0%
South West Queensland Pipeline	128.9	128.9	15.8	15.8	100.0%	100.0%
Wallumbilla Gladstone Pipeline	260.3	260.3	107.0	107.0	100.0%	100.0%
Jemena						
Darling Downs Pipeline	15.7	15.8	0.0	4.0	99.8%	0.0%
Eastern Gas Pipeline	71.6	71.6	0.0	15.8	100.0%	0.2%
Queensland Gas Pipeline	23.4	23.4	1.3	11.6	100.0%	10.9%
VicHub Pipeline	1.4	1.4	0.0	0.1	100.0%	0.0%
SEA Gas						
Port Campbell to Adelaide Pipeline	36.5	36.7	6.0	8.0	99.2%	74.6%
Port Campbell to Iona Pipeline	1.3	1.3	0.2	0.2	99.2%	65.1%
EPIC						
Moomba to Adelaide Pipeline System	37.3	37.3	13.6	13.6	100.0%	100.0%
Palisade						
Tasmanian Gas Pipeline	15.3	15.3	5.8	5.8	100.0%	100.0%

Sources: Part 23 financial information, October 2018, Table 2.1.
Notes:
[A]: Total revenue excluding related party transactions reported in Table 2.1.
[B]: Total revenue including related party transactions reported in Table 2.1.
[C]: Total costs less depreciation and excluding related party transactions reported in Table 2.1.
[D]: Total costs less depreciation and including related party transactions reported in Table 2.1.
[E] = [A] / [B] x 100
[F] = [C] / [D] x 100

V. Benchmarks for assessing access prices

154. In this section, we outline a number of cost-based pricing benchmarks using the principles discussed in Section III. Our pricing benchmarks are based on the cost of providing pipeline services. While benchmarks based on the value of capacity may be relevant, as we explained in section III, information required to estimate the value of capacity is not available as part of Part 23 financial disclosure. We detail the information available under Part 23 for our pricing benchmarks in subsection A and step through the calculations of our pricing benchmarks using Part 23 financial information in subsection B.

A. Cost-based information under Part 23

1. Summary

155. To calculate cost-based pricing benchmarks, we first identify the different cost components available from the Part 23 financial information (incremental costs, fixed operating costs, and

investment costs). For both fixed operating costs and investment costs, there is more than one potentially relevant estimate (ie, there are options). We summarise these cost components in Table 27. We step through the different cost components in the following subsections.

Table 27
Part 23 information for calculating cost-based pricing benchmarks

Components to cost-based pricing benchmarks	Information available under Part 23
[1] Incremental cost	Not identifiable
[2] Fixed operating costs	(a) Annual operating expenditure reported under the RCM (Table 4.1) (b) Total cost reported under the statement of revenue and expenses (i) Total direct and shared cost (minus depreciation) (Table 2.1) (ii) Total direct cost (minus depreciation) (Table 2.1)
[3] Investment cost	
[3.1] Asset value	(a) Depreciated book value method (i) Total assets excluding other non-depreciable assets (Table 3.1) (ii) Direct pipeline assets excluding other non-depreciable assets (Table 3.1) (b) Recovered capital method Total assets (Table 4.1)
[3.2] Depreciation	(a) Requires an assumption about depreciation profile (i) Straight-line depreciation (ii) Levelised depreciation (b) Requires an assumption about remaining asset life, not reported under Part 23
[3.3] Return on investment	Requires an assumption, but can be informed by certain benchmarks, including: (i) The inferred rates of return used in the RCM (ii) The inferred rates of return used in the RCM by other pipelines (iii) Rate of return determined for fully regulated pipelines (by the AER or the ERA)
[3.4] Taxes	A tax component is required if the rate of return on investment is post-tax, not identifiable under Part 23
[4] Allocator of fixed operating and investment costs	Contracted capacity or nameplate capacity
Other pricing benchmarks	
	Weighted average price Standing price

2. Incremental cost

156. Part 23 financial information does not allow one to identify the expenses that pipelines incur by transporting additional units of gas. We would expect these incremental costs to be very small relative to other costs of operating a pipeline.

3. Fixed operating costs

157. The following information can be used to estimate the fixed operating expenses of providing pipeline services.

a. The expenses for the reporting period 1 January 2018 – 30 June 2018, which service providers report in the "Statement of revenue and expenses" (Table 2.1 of the AER Template).

   i. The expenses for the reporting period 1 January 2018 – 30 June 2018 include not just operating expenses but also depreciation, which is not a fixed operating cost. We subtract depreciation from the total reported expenses to estimate the fixed operating expenses of the pipeline.

   ii. The magnitude of shared expenses reported by a pipeline depends on the allocation methods used by the service provider. A pricing benchmark that includes shared expenses might vary with the allocation methods, which in turn vary across service providers. We estimate pricing benchmarks with and without shared expenses in recognition of potential inconsistencies across service providers.

b. Historical operating expenses, reported in the RCM (Table 4.1 of the AER Template):

   i. The expenses for the reporting period 1 January 2018 – 30 June 2018 might not reflect the expenses that service providers typically incur (see Table 17). We use average historical annual operating expenses information reported under the RCM as another estimate of fixed operating costs.

   ii. We use the three-year period from 2015 to 2017 to estimate the average annual operating expenses for each pipeline. Our choice of three years is arbitrary; however, going too far back might mean that the information is no longer relevant to the current market conditions, or the conditions or operations of the pipelines. We do not use the 2018 information since some pipelines appear to report information for only six months whereas others report information for a full year (see Table 11).

4. Investment costs

158. As explained in our framework in section III, to calculate investment costs, we need information on (i) the current asset value, (ii) projected return on investment, and (iii) projected depreciation.

Asset value

159. Part 23 information provides two estimates for the current value of pipeline assets, one using the depreciated book value method and the other using the RCM.

160. We derive two estimates of the current asset value from the pipelines' reporting under the depreciated book value method: direct assets (excluding "other non-depreciable assets") and total assets (also excluding "other non-depreciable assets").

a. Total assets include direct assets and shared assets. The magnitude of shared assets depends on the service provider's allocation methods.

b. Shared assets account for a relatively small proportion of total assets for all pipelines except for those owned by Jemena. Jemena's shared assets consist largely of deferred tax assets and items such as "accrued receivables and amounts due from related parties".[174]

c. We exclude "other non-depreciable assets" since at least for some pipelines, this item includes goodwill, which presumably reflects the market value of pipeline capacity. Our pricing benchmarks are cost-based, and therefore, do not include "other non-depreciable assets".

Return on investment

161. Calculating the return on investment component of our pricing benchmarks requires an estimate of the expected rate of return on investment. We are able to infer the pipelines' historical rates of return from their reporting under the RCM to use as benchmarks, noting that these rates of returns might not correspond to the future opportunity cost of capital. We have also extracted information on the rate of return adopted by regulators in recent decisions for covered pipelines.

162. For each pipeline we consider the following rate of return benchmarks:

a. The most recent rate of return information assumed by the pipeline in its RCM reporting: we use the rate of return for 2017 because the information for 2018 reported by some pipelines appears to only be for a six-month period.

b. An average of recent years' rates of return assumed by the pipeline: we use 2015 – 2017 to estimate this average, except in the case of the Wallumbilla Gladstone Pipeline, where we use 2016 – 2018 since the 2015 rate of return appears unusually low.

c. The maximum and minimum rates of return assumptions across all pipelines in 2017. We exclude Tasmanian Gas Pipeline in our estimation of the maximum and minimum because, as explained in section IV.B (paragraph 132), the reporting of this pipeline for the RCM does not conform to what the AER Template specifies, and we are not able to make reasonable estimates of its rates of return on investment.

d. The average rate of return from a sample of AER and ERA determinations current as of 2017: We calculate the average rate of return from a sample of AER and ERA determinations for regulated gas pipelines and electricity networks (both distribution and transmission networks), listed in Appendix A—Documents cited, as another benchmark, while recognising that the risk of investing in covered and uncovered

[174] Jemena Basis of preparation – Eastern Gas Pipeline, p. 18, Jemena Basis of preparation – Queensland Gas Pipeline, p. 18, Jemena Basis of preparation –VicHub Pipeline, p. 13, Jemena Basis of preparation – Darling Downs Pipeline, p. 18.

pipelines may be different. For brevity, we refer to this benchmark as the 2017 average regulatory rate of return.

163. The above benchmarks are post-tax rates of return, meaning that they do not contain a component to reflect the income tax liability associated with the income generated by the pipeline.

164. Our pricing benchmarks therefore also need to incorporate an income tax cost component. We do not have sufficient information from the Part 23 disclosures to estimate the tax liabilities of the pipelines. In the absence of this information, we apply a constant "tax wedge" to the rate of return benchmarks to obtain "pre-tax" estimates of rates of return, although we know that this estimate is not accurate.[175] We illustrate our calculations in section B below.

Return of capital

165. For each different estimate of the current value of pipeline assets, we can estimate the corresponding depreciation (ie, return of capital) to include in the pricing benchmarks. The pricing benchmarks we calculate do not include the return of any expected future capital expenditures, as information on future capital expenditures is not available under Part 23.

166. The Part 23 financial information includes two values for the straight-line depreciation of assets during the reporting period 1 January 2018 – 30 June 2018 (under the "Statement of revenues and expenses", Table 2.1 of the AER Template): depreciation under direct costs and depreciation under shared costs. We use these two depreciation values to estimate straight-line depreciation of (i) total assets (direct and shared) and (ii) direct assets under the depreciated book value method. Depreciation of total assets is the sum of the two depreciation values, whereas depreciation of direct assets is the depreciation amount reported under direct costs.

167. Under the RCM, depreciation is the residual after subtracting operating expenses, net tax liabilities and allowed return on capital from revenue. As such, historical depreciation under the RCM is not a proxy for future depreciation. We therefore estimate straight-line depreciation for the asset value reported under the RCM. Our estimation requires an assumption about the remaining asset life. The Part 23 financial information includes an estimate of total asset life (at construction or acquisition), but not of the pipeline's remaining asset life. We estimate remaining asset life using information reported under the depreciated book value method. For each pipeline, we calculate the remaining asset life as the ratio of the current value of assets under the depreciated book value method to depreciation over the reporting period 1 January 2018 – 30 June 2018.

168. In our calculation of the remaining asset life, we can either use the current value of total assets or that of direct assets under the depreciated book value method, and the corresponding depreciation. We use direct pipeline assets, excluding land and easements, in

[175] For example, because of the issues discussed in the AER's December 2018 report on tax. See AER, "Final report – Review of regulatory tax approach", December 2018.

our calculations. We exclude land and easements because the AER Guideline does not allow for land and easements to be depreciated. We identify depreciation reported under "direct costs" in the "Statement of revenue and expenses" as depreciation for direct pipeline assets. Table 28 provides our estimates of the remaining asset life for each of the fourteen Part 23 pipelines.

Table 28
Estimated remaining direct asset lives as at 30 June 2018

	Depreciable direct assets in Table 3.1	Estimated one-year direct asset depreciation	Estimated remaining asset life
	AUD millions	AUD millions	years
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	81.6	1.2	69.5
Goldfields Gas Pipeline	186.1	6.3	29.5
Moomba to Sydney Pipeline	950.2	16.5	57.6
South East South Australia Pipeline	14.5	0.3	43.7
South West Queensland Pipeline	1,607.7	29.5	54.6
Wallumbilla Gladstone Pipeline	2,464.1	32.8	75.0
Jemena			
Darling Downs Pipeline	328.2	7.1	45.9
Eastern Gas Pipeline	533.4	29.8	17.9
Queensland Gas Pipeline	197.6	11.2	17.6
VicHub Pipeline	5.0	0.2	22.4
SEA Gas			
Port Campbell to Adelaide Pipeline	382.2	8.2	46.5
Port Campbell to Iona Pipeline	13.0	0.2	60.8
EPIC			
Moomba to Adelaide Pipeline System	348.0	17.7	19.7
Palisade			
Tasmanian Gas Pipeline	191.8	5.4	35.4

Sources: Part 23 financial information, October 2018, Tables 2.1 and 3.1.
Notes:
[A]: The depreciated book value of depreciable direct assets (excluding "land and easements" and "other non-depreciable pipeline assets") at 30 June 2018.
[B]: Direct asset depreciation reported in Table 2.1 divided by 180 (ie, the number of days between 1 January and 30 June in a common year) and multiplied by 365 to convert to an annual figure.
[C] = [A] / [B]

169. As discussed in our framework in section III, different depreciation profiles (for example, straight-line depreciation versus levelised depreciation) will result in different estimates of return of capital in any given year, and therefore, different cost-based pricing benchmarks. We apply levelised depreciation in one of our pricing benchmarks to illustrate the difference between this depreciation method and straight-line depreciation.

5. Cost allocation

170. The sum of fixed operating costs and investment costs, including returns of and on capital, and an estimate of taxes, is the total cost of providing pipeline services. In our pricing benchmark calculations, we consider a prospective shipper seeking access to the spare capacity of a pipeline. The different pricing benchmarks that we calculate reflect the different circumstances that determine how much of the total cost can reasonably be allocated to that shipper.

171. Fixed cost recovery requires a method to allocate fixed costs across the different shippers of a pipeline. One allocation method is to use the contracted quantity of transportation service. This means a user with a smaller contracted quantity contributes less to cost recovery than does a user with a larger contracted quantity. Using the WAP reporting, we obtain information on the total contracted MDQ for each pipeline. For each pipeline, we then calculate the cost per unit of contracted MDQ (ie, AUD per GJ per day of MDQ).

172. The total contracted MDQ information we obtain is for the "main service" (see Table 24). This total contracted MDQ information may not cover all of the revenues collected by the pipeline, due to the presence of both exempt services and other non-exempt services that generate a smaller amount of revenue (collectively referred to as "non-main" services). It may be reasonable to allocate some of the total cost reported under Part 23 to these non-main services. We account for this in our pricing benchmark calculations using two alternative adjustments methods.

    a. One adjustment method is to multiply the cost per unit of contracted MDQ by the proportion of total revenue that the main service generates. This calculation attributes total cost to the different services a pipeline provides in proportion to the revenue generated by the service.

    b. A second adjustment method is to subtract the revenue generated from "non-main" services from the pipeline's total costs, and use the remaining costs to estimate the cost per unit of contracted MDQ. This calculation allocates to "non-main" services costs equal to the revenues generated by those services.

173. The cost allocation described above allocates total cost to total contracted capacity, and does not allocate any cost to uncontracted capacity. An alternative allocation method is to use the pipelines' nameplate capacity, which is information that Part 23 pipeline owners are required to disclose. To the extent that pipelines are not fully contracted, a pricing benchmark that relies on nameplate capacity instead of contracted capacity may not allow the pipeline to recover its total costs.

6. Other pricing benchmarks reported under Part 23

174. Part 23 pipelines are also required to report the WAP for each service provided (unless exempt) and a standing price. We collect this information as points of comparison with the cost-based pricing benchmarks we derive, noting that these may not be cost-based prices.

B. Benchmark prices using Part 23 information

175. In this section, we calculate different pricing benchmarks corresponding to the different cost components discussed above. Since there is more than one estimate for each cost component, there are multiple permutations of pricing benchmarks. Our calculations in this section are intended to illustrate some, but not all, of these permutations. All of the calculations in this section use nameplate capacity to calculate unit costs.[176] We illustrate the use of contracted capacity at the end of the section.

1. Fixed operating costs

176. As summarised in subsection A above, there are three estimates or "options" that we can use from the Part 23 financial information to estimate the fixed operating costs for each pipeline: (i) average historical operating expenses from the RCM reporting, (ii) total costs for the reporting period 1 January 2018 – 30 June 2018 excluding depreciation, and (iii) direct costs for the reporting period 1 January 2018 – 30 June 2018 excluding depreciation. Table 29 reports our three estimates of operating expenses for each pipeline and the corresponding pricing benchmarks (AUD per day per GJ of MDQ). The different estimates of operating expenses can result in a large range of per unit operating costs for a given pipeline. For example, operating costs for Wallumbilla Gladstone Pipeline range from AUD 0.05 to AUD 0.39 per day per GJ of MDQ depending on whether historical operating expenses reported under the RCM or the total costs reported in the "Statement of revenue and expenses" for the reporting period 1 January 2018 – 30 June 2018 are used.

[176] Nameplate capacity can vary over time. Our report uses the nameplate capacity reported by service providers at the time we collected the information analysed in this report. See Appendix A—Documents cited for a list of the sources used for nameplate capacity.

Table 29
Three estimates of opex per unit of capacity
1 January 2018 – 30 June 2018

	Average six-month opex	Total costs less depreciation in Table 2.1	Direct costs less depreciation in Table 2.1	Nameplate capacity (180 days)	Per day per GJ of MDQ: Average six-month opex	Per day per GJ of MDQ: Total costs less depreciation in Table 2.1	Per day per GJ of MDQ: Direct costs less depreciation in Table 2.1
	AUD millions	AUD millions	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
APA							
Berwyndale Wallumbilla Pipeline	1.4	1.5	0.7	79,200	0.02	0.02	0.01
Goldfields Gas Pipeline	3.1	4.7	2.6	16,830	0.19	0.28	0.15
Moomba to Sydney Pipeline	14.8	11.6	6.7	97,740	0.15	0.12	0.07
South East South Australia Pipeline	0.3	0.4	0.1	7,200	0.04	0.06	0.02
South West Queensland Pipeline	16.0	15.8	8.7	133,920	0.12	0.12	0.06
Wallumbilla Gladstone Pipeline	14.9	107.0	95.0	271,800	0.05	0.39	0.35
Jemena							
Darling Downs Pipeline	5.1	4.0	2.3	145,800	0.03	0.03	0.02
Eastern Gas Pipeline	10.9	15.8	9.1	63,360	0.17	0.25	0.14
Queensland Gas Pipeline	7.9	11.6	8.5	25,740	0.31	0.45	0.33
VicHub Pipeline	0.1	0.1	0.1	51,300	0.00	0.00	0.00
SEA Gas							
Port Campbell to Adelaide Pipeline	5.6	8.0	6.0	48,420	0.12	0.17	0.12
Port Campbell to Iona Pipeline	0.3	0.2	0.2	72,000	0.00	0.00	0.00
EPIC							
Moomba to Adelaide Pipeline System	11.6	13.6	2.8	44,280	0.26	0.31	0.06
Palisade							
Tasmanian Gas Pipeline	0.0	5.8	5.8	23,220	0.00	0.25	0.25
Summary							
Minimum	0.0	0.1	0.1	7,200	0.00	0.00	0.00
Maximum	16.0	107.0	95.0	271,800	0.31	0.45	0.35

Sources: Part 23 financial information, October 2018, Tables 2.1 and 4.1; pipeline schematics.
Notes:
[A]: The average opex reported in Table 4.1 for the years 2015, 2016 and 2017 multiplied by 180 and divided by 365 to convert from an annual value to a six-month value (1 January to 30 June in a common year), equivalent to the numbers in [B] and [C].
[B]: Total costs for 1 January 2018 to 30 June 2018 reported in Table 2.1 less depreciation on all assets.
[C]: Direct costs for 1 January 2018 to 30 June 2018 reported in Table 2.1 less depreciation on direct assets.
[D]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[E] = ([A] x 1,000,000) / ([D] x 1,000)
[F] = ([B] x 1,000,000) / ([D] x 1,000)
[G] = ([C] x 1,000,000) / ([D] x 1,000)

2. Investment cost

a. Straight-line depreciation

Return of capital

177. Under the depreciated book value method, we use depreciation reported for the reporting period 1 January 2018 – 30 June 2018 as an estimate of the return of capital component. As discussed in subsection A, we have two estimates of straight-line depreciation for asset values under the depreciation book value method: depreciation on total assets and depreciation on direct assets.

178. Table 30 reports the depreciation of total assets for the period 1 January 2018 - 30 June 2018 and the corresponding return of capital per day per GJ of MDQ.

Table 30
Depreciation on total (direct and shared) assets per unit of capacity
1 January 2018 – 30 June 2018

	Total asset depreciation in Table 2.1	Nameplate capacity (180 days)	Total asset depreciation per day per GJ of MDQ
	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	0.6	79,200	0.01
Goldfields Gas Pipeline	3.1	16,830	0.18
Moomba to Sydney Pipeline	8.1	97,740	0.08
South East South Australia Pipeline	0.2	7,200	0.02
South West Queensland Pipeline	14.5	133,920	0.11
Wallumbilla Gladstone Pipeline	16.2	271,800	0.06
Jemena			
Darling Downs Pipeline	3.5	145,800	0.02
Eastern Gas Pipeline	15.3	63,360	0.24
Queensland Gas Pipeline	5.9	25,740	0.23
VicHub Pipeline	0.1	51,300	0.00
SEA Gas			
Port Campbell to Adelaide Pipeline	4.2	48,420	0.09
Port Campbell to Iona Pipeline	0.1	72,000	0.00
EPIC			
Moomba to Adelaide Pipeline System	9.0	44,280	0.20
Palisade			
Tasmanian Gas Pipeline	2.7	23,220	0.12

Sources: Part 23 financial information, October 2018, Table 2.1; pipeline schematics.
Notes:
[A]: Depreciation on direct and shared assets (1 January 2018 - 30 June 2018) reported in Table 2.1.
[B]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[C] = ([A] x 1,000,000) / ([B] x 1,000)

179. Table 31 reports the depreciation of direct pipeline assets for the period 1 January 2018 - 30 June 2018 and the corresponding return of capital per day per GJ of MDQ.

Table 31
Depreciation on direct assets per unit of capacity
1 January 2018 – 30 June 2018

	Direct asset depreciation in Table 2.1	Nameplate capacity (180 days)	Direct asset depreciation per day per GJ of MDQ
	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	0.6	79,200	0.01
Goldfields Gas Pipeline	3.1	16,830	0.18
Moomba to Sydney Pipeline	8.1	97,740	0.08
South East South Australia Pipeline	0.2	7,200	0.02
South West Queensland Pipeline	14.5	133,920	0.11
Wallumbilla Gladstone Pipeline	16.2	271,800	0.06
Jemena			
Darling Downs Pipeline	3.5	145,800	0.02
Eastern Gas Pipeline	14.7	63,360	0.23
Queensland Gas Pipeline	5.5	25,740	0.21
VicHub Pipeline	0.1	51,300	0.00
SEA Gas			
Port Campbell to Adelaide Pipeline	4.1	48,420	0.08
Port Campbell to Iona Pipeline	0.1	72,000	0.00
EPIC			
Moomba to Adelaide Pipeline System	8.7	44,280	0.20
Palisade			
Tasmanian Gas Pipeline	2.7	23,220	0.12

Sources: Part 23 financial information, October 2018, Table 2.1; pipeline schematics.
Notes:
[A]: Depreciation on direct assets (1 January 2018 - 30 June 2018) reported in Table 2.1.
[B]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[C] = ([A] x 1,000,000) / ([B] x 1,000)

180. The third option of depreciation using the Part 23 financial information is straight-line depreciation calculated from the current asset value under the RCM. Table 32 summarises our estimation of depreciation under the RCM. We first estimate half-year depreciation using the current asset value under the RCM and our estimated remaining asset life of the pipeline. We then estimate the corresponding return of capital per unit of capacity per day.

Table 32
Estimated RCM depreciation per unit of capacity

	Closing asset value based on Table 4.1	Estimated remaining asset life	Estimated half-year depreciation	Nameplate capacity (180 days)	Depreciation of RCM asset value per day per GJ of MDQ
	AUD millions	years	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	96.1	69.5	0.7	79,200	0.01
Goldfields Gas Pipeline	0.0	29.5	0.0	16,830	0.00
Moomba to Sydney Pipeline	2,083.6	57.6	17.8	97,740	0.18
South East South Australia Pipeline	36.3	43.7	0.4	7,200	0.06
South West Queensland Pipeline	2,082.7	54.6	18.8	133,920	0.14
Wallumbilla Gladstone Pipeline	1,436.7	75.0	9.4	271,800	0.03
Jemena					
Darling Downs Pipeline	194.0	45.9	2.1	145,800	0.01
Eastern Gas Pipeline	834.3	17.9	23.0	63,360	0.36
Queensland Gas Pipeline	1,018.1	17.6	28.5	25,740	1.11
VicHub Pipeline	3.7	22.4	0.1	51,300	0.00
SEA Gas					
Port Campbell to Adelaide Pipeline	406.4	46.5	4.3	48,420	0.09
Port Campbell to Iona Pipeline	13.8	60.8	0.1	72,000	0.00
EPIC					
Moomba to Adelaide Pipeline System	579.8	19.7	14.5	44,280	0.33
Palisade					
Tasmanian Gas Pipeline	12.9	35.4	0.2	23,220	0.01

Sources: Part 23 financial information, October 2018, Tables 3.1 and 4.1; pipeline schematics.
Notes:
[A]: The value of total assets calculated in the recovered capital method as of 30 June 2018.
[B]: Remaining asset life estimated as the value of direct depreciable assets in Table 3.1 divided by estimated annual depreciation on direct assets (reported depreciation in Table 3.3.1 on direct assets except land and easements during the reporting period multiplied by (365 / 180) to convert to an annual value).
[C] = [A] / [B] x 180 / 365 (ie, the number of days between 1 January and 30 June in a common year, 180, divided by 365).
[D]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[E] = ([C] x 1,000,000) / ([D] x 1,000)

181. Table 33 summarises the three different estimates of return of capital per day per GJ of MDQ. The differences in pipeline asset value resulting from (i) different asset valuation frameworks and from (ii) the inclusion/exclusion of shared assets. These differences give rise to a large range of depreciation (per unit of pipeline capacity per day). Take for example the case of Queensland Gas Pipeline. A pricing benchmark that accounts for direct asset depreciation might equal AUD 0.21 per day per GJ of MDQ, whereas one that accounts for total assets under the RCM might equal AUD 1.11 per day per GJ of MDQ.

Table 33
Investment cost: three measures of return of capital

	Total asset depreciation per day per GJ of MDQ	Direct asset depreciation per day per GJ of MDQ	Depreciation of RCM asset value per day per GJ of MDQ
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	0.01	0.01	0.01
Goldfields Gas Pipeline	0.18	0.18	0.00
Moomba to Sydney Pipeline	0.08	0.08	0.18
South East South Australia Pipeline	0.02	0.02	0.06
South West Queensland Pipeline	0.11	0.11	0.14
Wallumbilla Gladstone Pipeline	0.06	0.06	0.03
Jemena			
Darling Downs Pipeline	0.02	0.02	0.01
Eastern Gas Pipeline	0.24	0.23	0.36
Queensland Gas Pipeline	0.23	0.21	1.11
VicHub Pipeline	0.00	0.00	0.00
SEA Gas			
Port Campbell to Adelaide Pipeline	0.09	0.08	0.09
Port Campbell to Iona Pipeline	0.00	0.00	0.00
EPIC			
Moomba to Adelaide Pipeline System	0.20	0.20	0.33
Palisade			
Tasmanian Gas Pipeline	0.12	0.12	0.01

Sources: Part 23 financial information, October 2018, Tables 2.1, 3.1 and 4.1; pipeline schematics.
Notes:
[A]: Depreciation on all assets (1 January 2018 - 30 June 2018) per unit of nameplate capacity over 1 January to 30 June.
[B]: Depreciation on direct assets (1 January 2018 - 30 June 2018) per unit of nameplate capacity over 1 January to 30 June.
[C]: Depreciation on all assets estimated from the recovered capital method per unit of nameplate capacity over 1 January to 30 June.

Return on capital

182. As discussed in section A, there are several benchmarks for the rates of return on investment. For the sake of comparison, we use the 2017 average regulatory rate of return in our calculations. However, we illustrate below that any variation in the rate of return is likely to result in a significant impact on the benchmark prices. We first calculate a pricing benchmark to reflect a return on capital including taxes using the pipelines' assumed post-tax rate of return for 2017, which we infer from the RCM reporting. We then calculate a similar pricing benchmark using the 2017 average regulatory rate of return and provide a comparison of the two pricing benchmarks.

183. The different rate of return benchmarks we discuss in section A are post-tax rates of return, meaning that they do not contain a component to reflect the income tax liability associated with the income generated by the pipeline. Table 34 illustrates a method for grossing up rates

of return to reflect income tax, using the individual pipelines' assumption of post-tax rate of return for 2017 inferred from the RCM reporting.

Table 34
Estimation of taxes

Panel A: Assumed inputs		
Average regulatory return on debt	[A]	5.71%
Gearing	[B]	60%
Statutory tax rate	[C]	30%
Gamma	[D]	40%

Panel B: Estimating pre-tax rates of return on capital

	Pipeline rate of return 2017	Post-tax return on equity	Estimated pre-tax return on equity	Tax as a % of equity	Tax as a % of assets	Pre-tax rate of return
	[E]	[F]	[G]	[H]	[I]	[J]
APA						
Berwyndale Wallumbilla Pipeline	8.91%	13.72%	16.73%	3.01%	1.20%	10.12%
Goldfields Gas Pipeline	9.08%	14.12%	17.22%	3.10%	1.24%	10.32%
Moomba to Sydney Pipeline	9.03%	14.00%	17.07%	3.07%	1.23%	10.26%
South East South Australia Pipeline	8.97%	13.86%	16.90%	3.04%	1.22%	10.19%
South West Queensland Pipeline	8.91%	13.70%	16.70%	3.01%	1.20%	10.11%
Wallumbilla Gladstone Pipeline	8.82%	13.48%	16.44%	2.96%	1.18%	10.00%
Jemena						
Darling Downs Pipeline	7.99%	11.41%	13.92%	2.51%	1.00%	8.99%
Eastern Gas Pipeline	7.22%	9.47%	11.55%	2.08%	0.83%	8.05%
Queensland Gas Pipeline	7.81%	10.95%	13.36%	2.40%	0.96%	8.77%
VicHub Pipeline	6.90%	8.67%	10.57%	1.90%	0.76%	7.66%
SEA Gas						
Port Campbell to Adelaide Pipeline	6.89%	8.66%	10.55%	1.90%	0.76%	7.65%
Port Campbell to Iona Pipeline	6.78%	8.39%	10.23%	1.84%	0.74%	7.52%
EPIC						
Moomba to Adelaide Pipeline System	6.64%	8.03%	9.80%	1.76%	0.71%	7.35%
Palisade						
Tasmanian Gas Pipeline	0.31%	-7.78%	-9.49%	-1.71%	-0.68%	-0.37%

Sources: Part 23 financial information, October 2018, Table 4.1; AER and ERA regulatory determinations (see Appendix A—Documents cited).
Notes:
[A]: The average return on debt used in a sample of AER and ERA determinations active as of 2017.
[B]: The leverage assumption used in AER and ERA determinations active as of 2017.
[C]: The statutory corporate tax rate.
[D]: The value of imputation credits used in AER and ERA determinations active as of 2017.
[E]: The rate of return inferred for the year 2017 from the recovered capital method reporting.
[F] = ([E] - [A] x [B]) / (1 - [B])
[G] = [F] / (1 - [C] x (1 - [D]))
[H] = [G] - [F]
[I] = [H] x (1 - [B])
[J] = [E] + [I]

184. Our calculations in Table 34 are as follows. From the post-tax rate of return on total pipeline assets (column [E]), we first estimate the post-tax return on equity (column [F]) using an

assumed capital structure and an assumed rate of return on debt (rows [B] and [A]). We then use the post-tax return on equity to estimate the pre-tax return on equity (column [G]), taking into account the value of franking credits (row [D]). This gives us an estimate of a "tax wedge" on the rate of return on equity and then pipeline assets (column [H] and column [I], respectively). The tax wedge on the rate of return on pipeline assets is added on to the post-tax rate of return on pipeline assets to arrive at a pre-tax rate of return on pipeline assets (column [J]). Our calculation requires certain assumptions about the pipeline's capital structure, cost of debt, effective corporate tax rate, and value of franking credits. We do not have sufficient relevant information from the Part 23 disclosures to make these calculations, so we need to use assumptions. We use assumptions made by the AER in its recent regulatory determinations in our calculations, noting that these assumptions (i) are for regulated pipelines, (ii) might not reflect the actual circumstances of the uncovered pipelines, and (iii) are likely to be inconsistent with the service providers calculations of net tax liabilities and post-tax return.

185. Using our estimates of the tax wedge, we can calculate the return on capital component and the associated tax estimates for our pricing benchmarks. Table 35 illustrates one example of return on capital and the corresponding tax estimates. Table 35 uses the current asset value (as at 30 June 2018) under the RCM, the inferred rates of return from the RCM for 2017 for each pipeline, and the corresponding tax estimates in Table 34. Since Goldfields Gas Pipeline reports a zero asset value under the RCM, its investment cost is zero. Note that (i) different combinations of asset value and rates of return will result in different cost benchmarks for return on capital and taxes and (ii) the return on capital and the corresponding tax estimates are a function of the current asset value, which changes over time due to depreciation. The figures in Table 35 represent estimates of return on capital and the corresponding taxes based on the current asset value as at 30 June 2018.

Table 35
Investment cost: return on capital and taxes based on pipelines' 2017 inferred rates of return under the RCM

	Closing asset value based on Table 4.1	Pipeline rate of return 2017	Tax as a % of assets	Return on capital	Tax estimate	Nameplate capacity (180 days)	Return on capital per MDQ	Tax estimate per MDQ
	AUD millions	%	%	AUD millions	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
APA								
Berwyndale Wallumbilla Pipeline	96.1	8.91%	1.20%	4.2	0.6	79,200	0.05	0.01
Goldfields Gas Pipeline	0.0	9.08%	1.24%	0.0	0.0	16,830	0.00	0.00
Moomba to Sydney Pipeline	2,083.6	9.03%	1.23%	92.8	12.6	97,740	0.95	0.13
South East South Australia Pipeline	36.3	8.97%	1.22%	1.6	0.2	7,200	0.22	0.03
South West Queensland Pipeline	2,082.7	8.91%	1.20%	91.5	12.4	133,920	0.68	0.09
Wallumbilla Gladstone Pipeline	1,436.7	8.82%	1.18%	62.5	8.4	271,800	0.23	0.03
Jemena								
Darling Downs Pipeline	194.0	7.99%	1.00%	7.6	1.0	145,800	0.05	0.01
Eastern Gas Pipeline	834.3	7.22%	0.83%	29.7	3.4	63,360	0.47	0.05
Queensland Gas Pipeline	1,018.1	7.81%	0.96%	39.2	4.8	25,740	1.52	0.19
VicHub Pipeline	3.7	6.90%	0.76%	0.1	0.0	51,300	0.00	0.00
SEA Gas								
Port Campbell to Adelaide Pipeline	406.4	6.89%	0.76%	13.8	1.5	48,420	0.29	0.03
Port Campbell to Iona Pipeline	13.8	6.78%	0.74%	0.5	0.0	72,000	0.01	0.00
EPIC								
Moomba to Adelaide Pipeline System	579.8	6.64%	0.71%	19.0	2.0	44,280	0.43	0.05
Palisade								
Tasmanian Gas Pipeline	12.9	0.31%	-0.68%	0.0	0.0	23,220	0.00	0.00

Sources: Part 23 financial information, October 2018, Table 4.1; AER and ERA regulatory determinations; pipeline schematics.
Notes:
[A]: The value of total assets calculated in the recovered capital method as of 30 June 2018.
[B]: The rate of return inferred for the year 2017 from the recovered capital method reporting, from Table 12.
[C]: An estimate of tax liabilities, as a percentage of asset value, from Table 34.
[D] = [A] x [B] x 180 / 365 (ie, the number of days between 1 January and 30 June in a common year, 180, divided by 365).
[E] = [A] x [C] x 180 / 365 (ie, the number of days between 1 January and 30 June in a common year, 180, divided by 365).
[F]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[G] = ([D] x 1,000,000) / ([F] x 1,000)
[H] = ([E] x 1,000,000) / ([F] x 1,000)

186. Table 36 illustrates another example of return on capital which uses the 2017 average regulatory rate of return as opposed to the inferred rates of return from the RCM. The 2017 average regulatory rate of return is 6.34%. For the purpose of comparison, Table 36 uses the asset value under the RCM, as per Table 35. Comparing Table 35 to Table 36, a decrease in the post-tax rate of return from 9.03% to 6.34% in the case of Moomba to Sydney Pipeline results in a change in return on capital, inclusive of taxes, from AUD 1.10 to AUD 0.73 per day per GJ of MDQ. This illustrates that the assumption about the rate of return on investment can have a large impact on the calculation of a cost-based pricing benchmark.

Table 36
An estimate of return on capital and net tax liabilities per unit of capacity based on the average 2017 regulatory rate of return

	Closing asset value based on Table 4.1	2017 average regulatory rate of return	Tax as a % of assets	Return on capital	Tax estimate	Nameplate capacity (180 days)	Return on capital per MDQ	Tax estimate per MDQ
	AUD millions	%	%	AUD millions	AUD millions	TJ of MDQ x days	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
APA								
Berwyndale Wallumbilla Pipeline	96.1	6.34%	0.64%	3.0	0.3	79,200	0.04	0.00
Goldfields Gas Pipeline	0.0	6.34%	0.64%	0.0	0.0	16,830	0.00	0.00
Moomba to Sydney Pipeline	2,083.6	6.34%	0.64%	65.1	6.6	97,740	0.67	0.07
South East South Australia Pipeline	36.3	6.34%	0.64%	1.1	0.1	7,200	0.16	0.02
South West Queensland Pipeline	2,082.7	6.34%	0.64%	65.1	6.6	133,920	0.49	0.05
Wallumbilla Gladstone Pipeline	1,436.7	6.34%	0.64%	44.9	4.5	271,800	0.17	0.02
Jemena								
Darling Downs Pipeline	194.0	6.34%	0.64%	6.1	0.6	145,800	0.04	0.00
Eastern Gas Pipeline	834.3	6.34%	0.64%	26.1	2.6	63,360	0.41	0.04
Queensland Gas Pipeline	1,018.1	6.34%	0.64%	31.8	3.2	25,740	1.24	0.12
VicHub Pipeline	3.7	6.34%	0.64%	0.1	0.0	51,300	0.00	0.00
SEA Gas								
Port Campbell to Adelaide Pipeline	406.4	6.34%	0.64%	12.7	1.3	48,420	0.26	0.03
Port Campbell to Iona Pipeline	13.8	6.34%	0.64%	0.4	0.0	72,000	0.01	0.00
EPIC								
Moomba to Adelaide Pipeline System	579.8	6.34%	0.64%	18.1	1.8	44,280	0.41	0.04
Palisade								
Tasmanian Gas Pipeline	12.9	6.34%	0.64%	0.4	0.0	23,220	0.02	0.00

Sources: Part 23 financial information, October 2018, Table 2.1; pipeline schematics.
Notes:
[A]: The value of total assets calculated in the recovered capital method as of 30 June 2018.
[B]: The average post-tax WACC from a sample of AER and ERA determinations on pipeline rate of return that were active as of 2017.
[C]: An estimate of taxes, as a percentage of asset value, derived from [B].
[D] = [A] x [B] x 180 / 365 (the number of days between 1 January and 30 June in a common year, 180, divided by 365).
[E] = [A] x [C] x 180 / 365 (the number of days between 1 January and 30 June in a common year, 180, divided by 365).
[F]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).
[G] = ([D] x 1,000,000) / ([F] x 1,000)
[H] = ([E] x 1,000,000) / ([F] x 1,000)

b. Total investment costs

187. Table 37 illustrates one example of total investment costs for each pipeline. In Table 37 we use the asset value as at 30 June 2018 under the RCM and the 2017 average regulatory rate of return of 6.34%. Again, the figures shown in Table 37 (i) are sensitive to the choice of an asset valuation framework/method and the rate of return on investment and (ii) will change over time as the pipeline assets depreciate.

Table 37
Total investment costs (based on asset values in the RCM)

	Depreciation of RCM asset value per day per GJ of MDQ	Return on RCM asset value per day per GJ of MDQ	Tax estimate over RCM assets per day per GJ of MDQ	Total investment cost per day per GJ of MDQ
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	0.01	0.04	0.00	0.05
Goldfields Gas Pipeline	0.00	0.00	0.00	0.00
Moomba to Sydney Pipeline	0.18	0.67	0.07	0.92
South East South Australia Pipeline	0.06	0.16	0.02	0.23
South West Queensland Pipeline	0.14	0.49	0.05	0.68
Wallumbilla Gladstone Pipeline	0.03	0.17	0.02	0.22
Jemena				
Darling Downs Pipeline	0.01	0.04	0.00	0.06
Eastern Gas Pipeline	0.36	0.41	0.04	0.82
Queensland Gas Pipeline	1.11	1.24	0.12	2.47
VicHub Pipeline	0.00	0.00	0.00	0.00
SEA Gas				
Port Campbell to Adelaide Pipeline	0.09	0.26	0.03	0.38
Port Campbell to Iona Pipeline	0.00	0.01	0.00	0.01
EPIC				
Moomba to Adelaide Pipeline System	0.33	0.41	0.04	0.78
Palisade				
Tasmanian Gas Pipeline	0.01	0.02	0.00	0.03

Sources: Part 23 financial information, October 2018, Tables 2.1, 3.1 and 4.1; AER and ERA regulatory determinations; pipeline schematics.
Notes:
[A]: Depreciation of assets estimated as the current asset value under the RCM divided by estimated remaining asset life, expressed per day per GJ of MDQ.
[B]: Return on capital estimated as the current asset value under the RCM multiplied by the average regulatory rate of return for a sample of AER and ERA regulatory determinations, expressed per day per GJ of MDQ. The rate of return used is a post-tax rate of 6.34%.
[C]: An estimate of tax liabilities per day per GJ of MDQ, derived from the 2017 regulatory average rate of return. This accounts for a tax wedge of 0.64%.
[D] = [A] + [B] + [C]

c. Levelised depreciation

188. Asset valuation methods and rates of return on investment are not the only parameters that affect the calculation of total investment costs. The choice of depreciation profile can also have a significant impact on the total investment cost component of a pricing benchmark. Table 37 provides an example of total investment costs (AUD per day per GJ of MDQ) under the assumption of straight-line depreciation. Table 38 illustrates the change to total investment costs by applying levelised depreciation instead, using the Moomba to Adelaide Pipeline as an example.

189. Under the levelised depreciation approach illustrated here, the total investment costs are assumed to be recovered in equal annual payments over the remaining life of the pipeline.

At the beginning, when the asset value is large, a larger proportion of total investment costs is made up of return on investment and corresponding taxes. As the asset continues to depreciate and declines in value, the return on investment component decreases. Since the sum of return on investment, taxes, and return of investment is the same in each year over the remaining life of the pipeline, by assumption, the pattern of the return of investment component is the reverse: smaller depreciation at the beginning and larger depreciation towards the end of the asset life. Table 38 illustrates the time profile of the returns on and of capital for the Moomba to Adelaide Pipeline, assuming an asset value as at 30 June 2018 of AUD 579.8 million as reported under the RCM, the post-tax 2017 average regulatory rate of return on investment of 6.34%, which equates to 6.98% pre-tax, and an estimated remaining asset life of 19.7 years.

Table 38
Levelised depreciation profile for Moomba to Adelaide Pipeline System

Panel A: Profile inputs			
Estimated remaining asset life	years	[A]	19.7
2017 average regulatory rate of return	%	[B]	6.34%
Tax as a % of assets	%	[C]	0.64%
Pre-tax rate of return	%	[D]	6.98%
Nameplate capacity (365 days)	TJ of MDQ x days	[E]	89,790
Closing asset value based on Table 4.1	AUD millions	[F]	579.8

Panel B: Levelised depreciation profile

Period	Period length	Remaining asset life (start of period)	Nameplate capacity	Pre-tax average regulatory rate of return 2017	Asset value (start of period)	Investment cost of assets including tax	Return on assets including tax	Depreciation	Asset value (end of period)	Investment cost per day per GJ of MDQ
	years	years	TJ of MDQ x days	%	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	AUD per day per GJ of MDQ
	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]
1	1.00	19.70	89,790	6.98%	579.8	55.02	40.4	14.6	565.2	0.61
2	1.00	18.70	89,790	6.98%	565.2	55.02	39.4	15.6	549.7	0.61
3	1.00	17.70	89,790	6.98%	549.7	55.02	38.3	16.7	533.0	0.61
4	1.00	16.70	89,790	6.98%	533.0	55.02	37.2	17.8	515.1	0.61
5	1.00	15.70	89,790	6.98%	515.1	55.02	35.9	19.1	496.1	0.61
6	1.00	14.70	89,790	6.98%	496.1	55.02	34.6	20.4	475.6	0.61
7	1.00	13.70	89,790	6.98%	475.6	55.02	33.2	21.8	453.8	0.61
8	1.00	12.70	89,790	6.98%	453.8	55.02	31.7	23.4	430.4	0.61
9	1.00	11.70	89,790	6.98%	430.4	55.02	30.0	25.0	405.5	0.61
10	1.00	10.70	89,790	6.98%	405.5	55.02	28.3	26.7	378.7	0.61
11	1.00	9.70	89,790	6.98%	378.7	55.02	26.4	28.6	350.1	0.61
12	1.00	8.70	89,790	6.98%	350.1	55.02	24.4	30.6	319.5	0.61
13	1.00	7.70	89,790	6.98%	319.5	55.02	22.3	32.7	286.8	0.61
14	1.00	6.70	89,790	6.98%	286.8	55.02	20.0	35.0	251.8	0.61
15	1.00	5.70	89,790	6.98%	251.8	55.02	17.6	37.5	214.3	0.61
16	1.00	4.70	89,790	6.98%	214.3	55.02	15.0	40.1	174.3	0.61
17	1.00	3.70	89,790	6.98%	174.3	55.02	12.2	42.9	131.4	0.61
18	1.00	2.70	89,790	6.98%	131.4	55.02	9.2	45.9	85.6	0.61
19	1.00	1.70	89,790	6.98%	85.6	55.02	6.0	49.0	36.5	0.61
20	0.70	0.70	63,100	6.98%	36.5	38.27	1.8	36.5	0.0	0.61

Sources: EPIC's Part 23 financial information for MAPS, October 2018, Tables 2.1, 3.1 and 4.1; AER and ERA determinations (see Appendix A—Documents cited); pipeline schematics.

[A]: The estimated remaining life of direct assets at the end of the current reporting period. [B]: The average post-tax WACC from a sample of AER and ERA regulatory determinations active as of 2017. [C]: The ratio of tax to assets derived from [B]. [D] = [B] + [C]. [E]: The nameplate capacity of the pipeline's firm service for the period 1 January to 31 December in a common year (daily nameplate capacity multiplied by 365 days). [F]: The value of total assets calculated in the recovered capital method as of 30 June 2018. [G]: The length in years of the period to which the given variables apply. [H]: The estimated remaining life of direct assets at the start of each period. [I]: The annualised nameplate capacity of the pipeline's firm service multiplied by the length of the period in years. [J]: The pre-tax rate of return from [D]. [K]: The value of assets at the beginning of each period, which equals the value in column [O] for the immediately preceding period. The initial value is the closing value of assets in the RCM as at 30 June 2018. [L]: A levelised payment calculated from the total asset value under the recovered capital method as of 30 June 2018. This includes returns of and on capital, and a tax component, assuming that total assets have a future value of zero and that payments are made at the end of each period. Note that [L] is multiplied by ((1 + [J]) ^ [G] - 1) / [J] to adjust for period length. [M] = [K] x ((1 + [J]) ^ [G] - 1). [N] = [L] - [M]. [O] = [K] - [N]. [P] = ([L] x 1,000,000) / ([I] x 1,000).

190. Table 38 shows that a levelised depreciation assumption results in an estimate of total investment costs of AUD 0.61 per day per GJ of MDQ. This compares to AUD 0.78 per day per GJ of MDQ in Table 37, which uses a straight-line depreciation assumption. However, note that the estimated investment costs in Table 37 are for the asset value as at 30 June 2018. Under straight-line depreciation, the total investment costs to be recovered in each year over the remaining life of the pipeline will decline over time as the pipeline depreciates, assuming no future capital expenditure, as illustrated in Table 39.

Table 39
Straight-line depreciation profile for Moomba to Adelaide Pipeline System

Panel A: Profile inputs			
Estimated remaining asset life	years	[A]	19.7
2017 average regulatory rate of return	%	[B]	6.34%
Tax as a % of assets	%	[C]	0.64%
Pre-tax rate of return	%	[D]	6.98%
Nameplate capacity (365 days)	TJ of MDQ x days	[E]	89,790
Closing asset value based on Table 4.1	AUD millions	[F]	579.8

Panel B: Straight-line depreciation profile

Period	Period length	Remaining asset life (start of period)	Nameplate capacity	Pre-tax average regulatory rate of return 2017	Asset value (start of period)	Return on assets including tax	Depreciation	Investment cost of assets including tax	Asset value (end of period)	Investment cost per day per GJ of MDQ
	years	years	TJ of MDQ x days	%	AUD millions	AUD millions	AUD millions	AUD millions	AUD millions	AUD per day per GJ of MDQ
	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]
1	1.00	19.70	89,790	6.98%	579.8	40.4	29.4	69.87	550.4	0.78
2	1.00	18.70	89,790	6.98%	550.4	38.4	29.4	67.82	521.0	0.76
3	1.00	17.70	89,790	6.98%	521.0	36.3	29.4	65.77	491.5	0.73
4	1.00	16.70	89,790	6.98%	491.5	34.3	29.4	63.72	462.1	0.71
5	1.00	15.70	89,790	6.98%	462.1	32.2	29.4	61.66	432.7	0.69
6	1.00	14.70	89,790	6.98%	432.7	30.2	29.4	59.61	403.2	0.66
7	1.00	13.70	89,790	6.98%	403.2	28.1	29.4	57.56	373.8	0.64
8	1.00	12.70	89,790	6.98%	373.8	26.1	29.4	55.50	344.4	0.62
9	1.00	11.70	89,790	6.98%	344.4	24.0	29.4	53.45	315.0	0.60
10	1.00	10.70	89,790	6.98%	315.0	22.0	29.4	51.40	285.5	0.57
11	1.00	9.70	89,790	6.98%	285.5	19.9	29.4	49.35	256.1	0.55
12	1.00	8.70	89,790	6.98%	256.1	17.9	29.4	47.29	226.7	0.53
13	1.00	7.70	89,790	6.98%	226.7	15.8	29.4	45.24	197.3	0.50
14	1.00	6.70	89,790	6.98%	197.3	13.8	29.4	43.19	167.8	0.48
15	1.00	5.70	89,790	6.98%	167.8	11.7	29.4	41.13	138.4	0.46
16	1.00	4.70	89,790	6.98%	138.4	9.7	29.4	39.08	109.0	0.44
17	1.00	3.70	89,790	6.98%	109.0	7.6	29.4	37.03	79.5	0.41
18	1.00	2.70	89,790	6.98%	79.5	5.5	29.4	34.98	50.1	0.39
19	1.00	1.70	89,790	6.98%	50.1	3.5	29.4	32.92	20.7	0.37
20	0.70	0.70	63,100	6.98%	20.7	1.0	20.7	21.68	0.0	0.34

Sources: EPIC's Part 23 financial information for MAPS, October 2018, Tables 2.1, 3.1 and 4.1; AER and ERA determinations (see Appendix A—Documents cited); pipeline schematics.
Notes: [A]: The estimated remaining life of direct assets at the end of the current reporting period. [B]: The average post-tax WACC from a sample of AER and ERA regulatory determinations active as of 2017. [C]: The ratio of tax to assets derived from [B]. [D] = [B] + [C]. [E]: The nameplate capacity of the pipeline's firm service for the period 1 January to 31 December in a common year (daily nameplate capacity multiplied by 365 days). [F]: The value of total assets calculated in the recovered capital method as of 30 June 2018. [G]: The period length to which the given variables apply. [H]: The estimated remaining life of total assets at the start of each period. [I]: The annualised nameplate capacity of the pipeline's firm service multiplied by the length of the period in years. [J]: The pre-tax rate of return from [D]. [K]: The value of assets at the beginning of each period, which equals the value in column [O] for the immediately preceding period. The initial value is the closing value of assets in the RCM as at 30 June 2018 (from [F]). [L] = [K] x ((1 + [J]) ^ [G] - 1). [M] = [starting asset value] / [remaining asset life as at 30 June 2018] x [G]. [N] = [L] + [M]. [O] = [K] - [M]. [P] = ([N] x 1,000,000) / ([I] x 1,000).

d. Total costs

191. The total costs of operating a pipeline include the fixed operating costs and total investment costs. Table 40 illustrates an example of a pricing benchmark that reflects the total costs of operating a pipeline. The figures reported in Table 40 vary depending on which estimates of fixed operating costs, asset value and rate of return on investment, and which depreciation assumption are used. For ease of comparison, we use the asset value as at 30 June 2018 as reported under the RCM and the post-tax 2017 average regulatory rate of return on investment of 6.34%, and assume straight-line depreciation, as per Table 37. For fixed operating costs, we use total costs, excluding depreciation, over the reporting period 1 January 2018 – 30 June 2018, as reported in the "Statement of revenue and expenses".

Table 40
Example of estimating total cost per unit of capacity

	Opex	Return of capital	Return on capital		
One example of estimates from Part 23 financial information	Total costs less total asset depreciation per day per GJ of MDQ	Depreciation of RCM asset value per day per GJ of MDQ	Return on RCM assets per day per GJ of MDQ	Tax estimate per day per GJ of MDQ	Total cost per day per GJ of MDQ
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline	0.02	0.01	0.04	0.00	0.07
Goldfields Gas Pipeline	0.28	0.00	0.00	0.00	0.28
Moomba to Sydney Pipeline	0.12	0.18	0.67	0.07	1.03
South East South Australia Pipeline	0.06	0.06	0.16	0.02	0.29
South West Queensland Pipeline	0.12	0.14	0.49	0.05	0.79
Wallumbilla Gladstone Pipeline	0.39	0.03	0.17	0.02	0.61
Jemena					
Darling Downs Pipeline	0.03	0.01	0.04	0.00	0.09
Eastern Gas Pipeline	0.25	0.36	0.41	0.04	1.06
Queensland Gas Pipeline	0.45	1.11	1.24	0.12	2.92
VicHub Pipeline	0.00	0.00	0.00	0.00	0.01
SEA Gas					
Port Campbell to Adelaide Pipeline	0.17	0.09	0.26	0.03	0.54
Port Campbell to Iona Pipeline	0.00	0.00	0.01	0.00	0.01
EPIC					
Moomba to Adelaide Pipeline System	0.31	0.33	0.41	0.04	1.09
Palisade					
Tasmanian Gas Pipeline	0.25	0.01	0.02	0.00	0.28

Sources: Part 23 financial information, October 2018, Tables 2.1, 3.1 and 4.1; AER and ERA determinations; pipeline schematics.

Notes:

[A]: Total costs less total asset depreciation as reported in Table 2.1 (1 January 2018 - 30 June 2018), expressed per day per GJ of MDQ.

[B]: Total asset depreciation as estimated from the asset values reported under the RCM, as reported in Table 4.1 as at 30 June 2018, using straight-line depreciation, expressed per day per GJ of MDQ.

[C]: Asset values reported under the RCM as of 30 June 2018 as reported in Table 4.1 multiplied by the average post-tax WACC from a sample of AER and ERA determinations active as of 2017, which is a post-tax rate of return of 6.34%, expressed per day per GJ of MDQ.

[D]: The closing asset value as at 30 June 2018 as reported in Table 4.1 multiplied by an estimated tax wedge over assets of 0.64% (estimated from the average rate of return from a sample of AER and ERA determinations active as of 2017), expressed per day per GJ of MDQ.

[E] = [A] + [B] + [C] + [D]

192. The magnitude of the pricing benchmarks in Table 40 will vary if different choices are made for (i) the estimates of fixed operating costs, (ii) the asset values, (iii) the rate of return on investment, (iv) the depreciation assumption, and (v) the estimation of taxes. Table 41 illustrates the impact on our calculations when the estimates of (i) fixed operating costs and (ii) asset values change. Both of these elements have different options/estimates available from the Part 23 financial information. Note that changing the assumptions about depreciation and the rate of return on investment will also have a substantial impact on the pricing benchmark calculations, as we illustrate above. For simplicity, Table 41 uses straight-line depreciation and the post-tax 2017 average regulatory rate of return of 6.34%. Table 41 summarises the range of fixed operating costs and total investment costs for each pipeline using the different estimates reported under Part 23 financial information. Table 41 shows that simply changing the inputs by using different estimates provided under Part 23 financial information can result in a wide range of pricing benchmarks for most pipelines. We emphasise that (i) the high and low values in Table 41 for each pipeline reflect different "choices" of the estimates provided under Part 23 financial information and (ii) the objective of estimating the ranges of "low" and "high" in Table 41 is to understand the impact on the calculation of a benchmark price when different options available using Part 23 information are used. These ranges do not necessarily include either the highest or lowest benchmark that could be calculated for an individual pipeline using Part 23 information.

Table 41
Estimates of costs using different options from the Part 23 financial information

	Operating costs		Investment costs including tax		Total cost	
	Low	High	Low	High	Low	High
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	0.01	0.02	0.04	0.05	0.05	0.07
Goldfields Gas Pipeline	0.15	0.28	0.00	0.57	0.15	0.85
Moomba to Sydney Pipeline	0.07	0.15	0.42	0.92	0.49	1.07
South East South Australia Pipeline	0.02	0.06	0.09	0.23	0.11	0.29
South West Queensland Pipeline	0.06	0.12	0.52	0.68	0.59	0.79
Wallumbilla Gladstone Pipeline	0.05	0.39	0.22	0.38	0.27	0.77
Jemena						
Darling Downs Pipeline	0.02	0.03	0.06	0.14	0.08	0.17
Eastern Gas Pipeline	0.14	0.25	0.53	0.82	0.67	1.06
Queensland Gas Pipeline	0.31	0.45	0.49	2.47	0.79	2.92
VicHub Pipeline	0.00	0.00	0.00	0.01	0.01	0.01
SEA Gas						
Port Campbell to Adelaide Pipeline	0.12	0.17	0.36	0.38	0.48	0.54
Port Campbell to Iona Pipeline	0.00	0.00	0.01	0.01	0.01	0.01
EPIC						
Moomba to Adelaide Pipeline System	0.06	0.31	0.47	0.78	0.53	1.09
Palisade						
Tasmanian Gas Pipeline	0.00	0.25	0.03	0.43	0.03	0.68

Sources: Part 23 financial information, Tables 2.1, 3.1, and 4.1; pipeline schematics; AER and ERA regulatory determinations (see Appendix A—Documents cited).
Notes:
[A] and [B]: The minimum and maximum values, respectively, for each pipeline out of "Total costs less depreciation" from Table 2.1 (1 January 2018 - 30 June 2018), "Direct costs less depreciation on direct assets" from Table 2.1 (1 January 2018 - 30 June 2018), and the average of operating expenses reported in Table 4.1 over the years 2015 to 2017.
[C] and [D]: The minimum and maximum values for the sum of return on and return of capital, inclusive of taxes, based on three options for asset value: total assets excluding "other non-depreciable assets' in Table 3.1, direct assets excluding "other non-depreciable assets" in Table 3.1, and the current asset value under the RCM in Table 4.1. For the first two asset values, depreciation is taken from Table 2.1. For the third asset value (the RCM asset value as of 30 June 2018), straight-line depreciation is calculated from an estimated remaining asset life. For all asset values, return on capital is calculated using the average regulatory post-tax rate of return taken from a sample of determinations by the AER and the ERA active as of 2017. The post-tax rate of return on assets is 6.34%, the estimated tax wedge is 0.64%, resulting in a pre-tax rate of return on assets of 6.98%.
[E] = [A] + [C]
[F] = [B] + [D]

193. Table 42 summarises the low and high total costs in Table 41 together with the WAP for the main service and the standing price reported for each pipeline. For most pipelines, a pricing benchmark that reflects the total investment cost at a regulatory rate of return on investment tends to be lower than the WAP and the standing price. This is not the case for Moomba to Sydney Pipeline, Darling Downs Pipeline, Queensland Gas Pipeline, Moomba to Adelaide Pipeline System and South East South Australia Pipeline. However, as noted above, our range of total costs in Table 42 is derived from (i) the 2017 average regulatory rate of return of 6.34%, and (ii) certain assumptions about taxes as well as straight-line depreciation. Any variation to these assumptions, such as a different rate of return, will result in a different range. The high and low cost-based pricing benchmarks shown in the first two columns of

Table 42 are both consistent with (and derived from) the financial information disclosed under Part 23 for each pipeline. However, prices outside the range shown in Table 42 may also be consistent with the Part 23 information if different assumptions, such as a different rate of return, are used. Table 42 also shows that for some pipelines, the standing price is slightly lower than the WAP, for example, Wallumbilla Gladstone Pipeline, Moomba to Adelaide Pipeline System and Tasmanian Gas Pipeline.[177]

[177] Note that the Moomba to Adelaide Pipeline System standing price is reported in 2017 dollars, whereas the weighted average price is for the period 1 January 2018–30 June 2018. (EPIC Basis of Preparation – Moomba to Adelaide Pipeline System, p. 8.)

Table 42
Estimated pricing benchmarks based on the Part 23 financial information, WAP and standing prices

	Total cost estimate: low	Total cost estimate: high	Weighted average price (1 January 2018 - 30 June 2018)	Standing price for pipeline firm service
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ (unless indicated otherwise)	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]
APA				
Berwyndale Wallumbilla Pipeline	0.05	0.07		0.24
Goldfields Gas Pipeline	0.15	0.85	1.72	
Moomba to Sydney Pipeline	0.49	1.07	0.80	1.10
South East South Australia Pipeline	0.11	0.29		0.16
South West Queensland Pipeline	0.59	0.79	0.94	1.20 - 1.40
Wallumbilla Gladstone Pipeline	0.27	0.77	0.95	0.93
Jemena				
Darling Downs Pipeline	0.08	0.17		0.10 - 0.21
Eastern Gas Pipeline	0.67	1.06	1.16	1.30
Queensland Gas Pipeline	0.79	2.92	0.86	1.02
VicHub Pipeline	0.01	0.01	0.07	0.07
SEA Gas				
Port Campbell to Adelaide Pipeline	0.48	0.54	0.62	0.90
Port Campbell to Iona Pipeline	0.01	0.01		0.08
EPIC				
Moomba to Adelaide Pipeline System	0.53	1.09	0.79	0.77
Palisade				
Tasmanian Gas Pipeline	0.03	0.68	1.93	1.89

Sources: Part 23 financial information, Tables 2.1, 3.1, 4.1 and 5.1; AER and ERA regulatory determinations (see Appendix A—Documents cited); pipeline schematics; pipeline documents on standing price (see Appendix A—Documents cited).
Notes:
Berwyndale Wallumbilla Pipeline's revenue is mostly exempt from weighted average price reporting. Its main service in the current reporting period was interruptible or as available transportation service charged on a postage stamp basis, for which it reported approximately AUD 30 thousand in revenue and 150 TJ of throughput, resulting in a weighted average price of AUD 0.20 per GJ of throughput for the period 1 January 2018 – 30 June 2018. Goldfields Gas Pipeline charges a toll charge of $AU 0.3775 per day per GJ of MDQ and a capacity reservation charge of $AU 0.0029 per day per GJ per kilometre.
[A]: See Table 41 column [E].
[B]: See Table 41 column [F].
[C]: The weighted average price of the pipeline's main service as reported in Table 5.1.
[D]: The standing price of firm service on the pipeline, current as of June 2019.

194. The calculations above use the pipelines' nameplate capacity to allocate costs. We use the same low and high pricing benchmarks estimated in Table 41, and re-estimate them using contracted MDQ of the main service instead of nameplate capacity. These estimates are summarised in Table 43. Table 43 again illustrates that there is a wide range of cost-based pricing benchmarks.

Table 43
Comparison of access prices per unit of nameplate MDQ to access prices per unit of contracted MDQ

	Total cost estimate: low	Total cost estimate: high	Nameplate capacity (180 days)	Main service contracted MDQ in Table 5.1	Total cost estimate: low	Total cost estimate: high
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	TJ of MDQ x days	TJ of MDQ x days	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline	0.05	0.07	79,200			
Goldfields Gas Pipeline	0.15	0.85	16,830	12,992.7	0.20	1.10
Moomba to Sydney Pipeline	0.49	1.07	97,740	42,264.2	1.12	2.47
South East South Australia Pipeline	0.11	0.29	7,200			
South West Queensland Pipeline	0.59	0.79	133,920	94,891.3	0.83	1.12
Wallumbilla Gladstone Pipeline	0.27	0.77	271,800	273,310.0	0.27	0.76
Jemena						
Darling Downs Pipeline	0.08	0.17	145,800			
Eastern Gas Pipeline	0.67	1.06	63,360	48,815.7	0.87	1.38
Queensland Gas Pipeline	0.79	2.92	25,740	25,482.2	0.80	2.95
VicHub Pipeline	0.01	0.01	51,300	17,195.0	0.02	0.04
SEA Gas						
Port Campbell to Adelaide Pipeline	0.48	0.54	48,420	56,520.0	0.41	0.47
Port Campbell to Iona Pipeline	0.01	0.01	72,000			
EPIC						
Moomba to Adelaide Pipeline System	0.53	1.09	44,280	30,103.0	0.78	1.60
Palisade						
Tasmanian Gas Pipeline	0.03	0.68	23,220	3,351.2	0.19	4.72

Sources: Part 23 financial information, Tables 2.1, 3.1, 4.1 and 5.1; AER and ERA regulatory determinations (see Appendix A—Documents cited); pipeline schematics.

Notes:

Pipelines that do not report weighted prices under Table 5.1 (Darling Downs Pipeline and Port Campbell to Iona Pipeline) or for which the main service is charged on a volumetric basis (Berwyndale Wallumbilla Pipeline) do not provide information on contracted capacity.

[A]: The pipeline's "low" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on nameplate capacity.

[B]: The pipeline's "high" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on nameplate capacity.

[C]: The nameplate capacity of the pipeline's firm service for the period 1 January to 30 June in a common year (daily nameplate capacity multiplied by 180 days).

[D]: The capacity of main service contracted for the period 1 January 2018 – 30 June 2018 and reported in Table 5.1.

[E] = [A] x [C] / [D]

[F] = [B] x [C] / [D]

195. As explained in subsection A, the total contracted MDQ information we obtain is for the main service. The pipeline may have contracts to provide other services, and these are not included in the reported total contracted MDQ. It may be reasonable to allocate some of the total costs reported under Part 23 to these non-main services and therefore we use two alternative adjustments methods. Table 44 illustrates our first adjustment method, whereby we multiply the estimated pricing benchmarks by the ratio of main service revenue to total revenue. Table 45 illustrates our second adjustment method, whereby we allocate to "non-

main" services costs equal to the revenues generated by those services. We do this by subtracting the revenue generated from "non-main" services from the pipeline's total costs, and use the remaining costs to estimate the cost per GJ of contracted (main-service) MDQ.

Table 44
Accounting for other services according to proportion of revenue

	Total cost estimate: low	Total cost estimate: high	Main service revenue as a % of total revenue	Total cost estimate: low adjusted for share of revenue	Total cost estimate: high adjusted for share of revenue
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	%	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]
APA					
Berwyndale Wallumbilla Pipeline			0.4%		
Goldfields Gas Pipeline	0.20	1.10	69.6%	0.14	0.77
Moomba to Sydney Pipeline	1.12	2.47	48.6%	0.55	1.20
South East South Australia Pipeline					
South West Queensland Pipeline	0.83	1.12	69.4%	0.57	0.78
Wallumbilla Gladstone Pipeline	0.27	0.76	100.0%	0.27	0.76
Jemena					
Darling Downs Pipeline					
Eastern Gas Pipeline	0.87	1.38	78.8%	0.69	1.09
Queensland Gas Pipeline	0.80	2.95	93.7%	0.75	2.76
VicHub Pipeline	0.02	0.04	90.9%	0.02	0.04
SEA Gas					
Port Campbell to Adelaide Pipeline	0.41	0.47	96.1%	0.39	0.45
Port Campbell to Iona Pipeline					
EPIC					
Moomba to Adelaide Pipeline System	0.78	1.60	63.7%	0.50	1.02
Palisade					
Tasmanian Gas Pipeline	0.19	4.72	42.4%	0.08	2.00

Sources: Part 23 financial information, Tables 2.1, 3.1, 4.1 and 5.1; AER and ERA regulatory determinations; pipeline schematics.

Notes:

Pipelines that do not report weighted prices in Table 5.1 or for which the main service is charged on a volumetric basis do not provide information on contracted capacity, which is why their price values are missing in the above.

[A]: The pipeline's "low" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on contracted capacity.

[B]: The pipeline's "high" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on contracted capacity.

[C]: The ratio of main service revenue in Table 5.1 to total revenue in Table 2.1 (1 January 2018 to 30 June 2018). Adjusting the access price of the main service for this ratio implies an allocation of costs between services in proportion to the revenues of those services.

[D] = [A] x [C]

[E] = [B] x [C]

Table 45
Accounting for other services according to value of revenue

	Total cost estimate: low	Total cost estimate: high	Total revenue in Table 2.1 less main service revenue	Main service contracted MDQ in Table 5.1	Total cost estimate: low adjusted for non-main revenue	Total cost estimate: high adjusted for non-main revenue
	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ	AUD millions	TJ of MDQ per day	AUD per day per GJ of MDQ	AUD per day per GJ of MDQ
	[A]	[B]	[C]	[D]	[E]	[F]
APA						
Berwyndale Wallumbilla Pipeline			6.8			
Goldfields Gas Pipeline	0.20	1.10	9.8	12,992.7	-0.55	0.35
Moomba to Sydney Pipeline	1.12	2.47	35.9	42,264.2	0.28	1.62
South East South Australia Pipeline						
South West Queensland Pipeline	0.83	1.12	39.4	94,891.3	0.41	0.71
Wallumbilla Gladstone Pipeline	0.27	0.76	0.0	273,310.0	0.27	0.76
Jemena						
Darling Downs Pipeline						
Eastern Gas Pipeline	0.87	1.38	15.2	48,815.7	0.56	1.07
Queensland Gas Pipeline	0.80	2.95	1.5	25,482.2	0.74	2.89
VicHub Pipeline	0.02	0.04	0.1	17,195.0	0.01	0.04
SEA Gas						
Port Campbell to Adelaide Pipeline	0.41	0.47	1.4	56,520.0	0.38	0.44
Port Campbell to Iona Pipeline						
EPIC						
Moomba to Adelaide Pipeline System	0.78	1.60	13.5	30,103.0	0.33	1.15
Palisade						
Tasmanian Gas Pipeline	0.19	4.72	8.8	3,351.2	-2.44	2.09

Sources: Part 23 financial information, Tables 2.1, 3.1, 4.1 and 5.1; AER and ERA regulatory determinations; pipeline schematics.

Notes:

Pipelines that do not report weighted prices in Table 5.1 or for which the main service is charged on a volumetric basis do not provide information on contracted capacity, which is why their price values are missing in the above. Darling Downs Pipeline and Port Campbell to Iona Pipeline do not report enough information in Table 5.1 to identify a main service, which is why the revenue of non-main services per GJ of MDQ for these pipelines is missing.

[A]: The pipeline's "low" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on contracted capacity.

[B]: The pipeline's "high" total cost estimate in Table 41, assuming an average regulatory rate of return of 6.34% and a tax wedge over assets of 0.64%, expressed per day per GJ of MDQ based on contracted capacity.

[C]: Total revenue in Table 2.1 less main service revenue reported in Table 5.1.

[D]: Contracted capacity of the pipeline's main service in the current reporting period (1 January 2018 - 30 June 2018).

[E] = [A] - ([C] x 1,000,000) / ([D] x 1,000)

[F] = [B] - ([C] x 1,000,000) / ([D] x 1,000)

VI. Assessment of the Part 23 requirements

196. This section discusses the consistency and usability of the Part 23 financial information. Our discussion in this section relies on our review of the BoP and the reported information in section IV, and the pricing benchmarks calculated in section V. We also discuss the cost for service providers of complying with their disclosure obligations, and the cost of shippers or other stakeholders in using the Part 23 financial information in this section.

A. Consistency of the reported information

197. When we discuss consistency of reported information, we mean that a particular item of information (eg, operating expenses) should include the same type of costs for one pipeline as for another, and for a single pipeline should include the same information across the different tables in the AER Template where the item is reported. Consistency is important because a lack of consistency may imply that the AER Guideline is not sufficiently clear and is open to multiple interpretations. Inconsistency in the reported information, either across pipelines or within the same workbook of a pipeline, means that it is not straightforward for shippers to identify and understand certain cost elements. Where there is inconsistency across pipelines, greater reliance has to be placed on the BoP, which is different for each pipeline, rather than on the AER Guideline, in order to understand what the reported information represents and how it was derived. Furthermore, where information is reported consistently, this would facilitate shippers making comparisons across pipelines, which may be helpful for identifying cost elements to focus on in the context of a negotiation or arbitration.

198. There are variations in the financial information reported under Part 23 across pipelines, as well as across different tables reported by the same pipeline. These variations arise for a number of reasons.

199. As detailed in section IV, information in the same field for different pipelines might not be comparable since the AER Template and the AER Guideline allow pipelines to (i) report estimated information instead of actual recorded information, (ii) apply different assumptions in their calculations (eg, asset lives or assumptions under the RCM calculations, (iii) apply different allocators to allocate shared assets and expenses, and (iv) include additional information under "catch-all" categories such as "other assets" or "other shared costs". While these differences do not necessarily mean that the reporting of one pipeline is more or less reliable than others, it might be difficult for shippers to assess and use the reported information. For example, it appears that APA does not allocate shared costs or shared supporting assets across the different pipelines, but instead estimates what each pipeline would have spent if it had operated as a stand-alone business. APA also adds "other direct costs" as an adjustment to its operating expenses.[178] Another example is the inclusion of "other assets" and "deferred tax assets" by Jemena in shared assets. It is unclear (i) whether these asset categories also exist in the case of other pipelines but are not reported or whether they are specific to Jemena, and (ii) how accurately APA has reported its total operating expenses. As a result, it is unclear how to interpret the differences across pipelines with regard to, for example, asset composition or expense composition.

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[178] APA Basis of Preparation, p. 9. "Other direct costs" is a line item in Table 2.1 of the AER Template. It is not clear whether this line item includes only APA's adjustment described above, or also includes other costs.

200. An area in which service providers differ significantly is the calculations of asset value under the RCM. The AER states that "[t]he RCM asset valuation is intended to align with the building block approach applied to regulated pipelines, in situations where the regulated pipeline was constructed after the regulatory framework for gas pipelines came into effect (ie, post November 1997)".[179] However, the calculations of the RCM require several assumptions, which differ across service providers. These assumptions may have a significant impact on the resulting asset value, which in turn has a large impact on the calculation of cost-based pricing benchmarks.

201. In addition to inconsistencies across pipelines, there are also inconsistencies in information reported by the same pipeline, sometimes due to inconsistencies within the AER Template. The AER Template requires information that might refer to the same underlying items to be reported across different tables. Examples include operating expenses, as we summarise in Table 17, or revenue, as we summarise in Table 23. Another example is depreciation, which is reported in the "Statement of revenue and expenses" (Table 2.1), as well in "Statement of pipeline assets" (Table 3.1) and "Depreciation" (Tables 3.3.1 and 3.3.2).

    a. With regard to expenses, Table 17 shows that the historical expenses reported under the RCM might be different in nature to the total costs reported in the "Statement of revenue and expenses", the reason for which cannot be fully understood from the BoP. This can have an impact on the identification of the fixed operating costs of the pipelines.

    b. With regard to revenue, some pipelines do not report the magnitude of exempt revenue either in their WAP reporting or in their "Statement of revenue and expenses".

    c. With regard to depreciation, depreciation is reported in the AER Template in (i) the "Depreciation" worksheet (Table 3.3), (ii) the "Statement of pipeline assets" (Table 3.1), and (iii) the "Statement of revenue and expenses" (Table 2.1). The "Depreciation" tab in the AER Template consists of two separate tables, Table 3.3.1 for "Fixed assets at costs – pipeline assets" and Table 3.3.2 for "Shared assets at costs". These two tables report depreciation differently. The wording specified in the AER Template (i) appears to have resulted in inconsistencies in the reported information across pipelines, as explained in paragraph 123, and (ii) makes it difficult to reconcile the information on depreciation across the different tables.

202. Since service providers are allowed to report construction cost or acquisition cost under the depreciated book value method, but only construction cost under the RCM, the reporting under the two asset valuation frameworks within the Part 23 financial information can be different from each other and the differences can be difficult to reconcile. Aside from the fact that the depreciated book value method and the RCM are two different frameworks of valuing pipeline assets, inconsistencies between the two frameworks can arise due to differences in (i) the starting year of reporting, and thus the starting point of pipeline

[179] AER Explanatory Statement, p. 4.

depreciation, (ii) the initial asset value, and the (iii) reported amount of capital expenditure. While (i) and (ii) can occur if service provider reports construction cost under the RCM and acquisition cost under the depreciated book value, we do not fully understand the inconsistencies with regard to (iii), as illustrated in Table 15. Often there is not sufficient information from the BoP or from the reported information to understand why the construction year might be different from the first year of reporting under the RCM, when the pipeline was acquired, whether the acquisition year is the year in which depreciation under the depreciated asset value starts, or whether the differences in the initial asset value is indeed due to the use of construction cost versus acquisition cost. Coupled with the differences across service providers in the assumptions underlying the calculations in the RCM, it can be difficult to understand or estimate the investment cost associated with each pipeline.

203. Within the framework of the depreciated book value method, as we illustrate in Table 5, it can be time-consuming to fully examine and understand the reported information across the different tables within the AER Template. These inconsistencies do not necessarily have a large impact on the end asset value under the depreciated book value method, but revisions to the template can potentially help to standardise the reported information further, reducing the cost of using the information.

204. While some of the above observations might not have a substantial impact on how the reported information can be used to arrive at an understanding of the total costs of pipeline operations, they do have an impact on the time and effort required to dissect and understand the reported information. With regard to differences in information reported across pipelines, shippers and other stakeholders can only identify these differences by compiling and comparing the reported information. If a shipper only focuses on the information reported by the pipeline to which it is seeking access, it is unlikely to be able to identify and understand how the same line item in the financial reporting of different pipelines might have included different information. The ability to compare across pipelines may be helpful for identifying cost elements to focus on in the context of a negotiation or an arbitration.

B. Usability of the reported information

205. Part 23 financial information obligations were introduced subsequent to Dr Vertigan's findings and recommendations. One of Dr Vertigan's recommendations was for "the disclosure and transparency of pipeline service pricing and contract terms and conditions [to] be enhanced, including requiring the provision of information on the full range of pipeline services which are available or sought".[180] Part 23 states that "[t]he objective of this Part is to facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which, for

[180] Dr Michael Vertigan AC, "Examination of the current test for the regulation of gas pipelines," 14 December 2016, p. 100.

the purposes of this Part, is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market".[181]

206. The information reported under Part 23 provides shippers and other stakeholders with an understanding of the costs of operating a pipeline, the revenue that a pipeline has been generating, and average prices at which services have been provided. This information, to a certain extent, is helpful for shippers to arrive at certain cost-based pricing benchmarks for accessing the pipeline. However, there are a number of limitations to the Part 23 financial information.

207. First, the lack of clarity and the inconsistencies in the reported information mean that (i) it can be challenging to fully understand and identify the different cost components for a pipeline, and (ii) calculations can result in a wide range of cost-based pricing benchmarks.

    a. Given the nature of pipeline operations, it is to be expected that a range of cost-based pricing benchmarks that spans avoidable cost, fixed cost, and investment cost will be wide. However, wide ranges of cost-based pricing benchmarks calculated from Part 23 financial information also result from a lack of clarity in the reported information. For example, a prospective shipper looking to estimate the fixed operating costs of a pipeline might have difficulty extracting a well-defined and transparent estimate, as illustrated in Table 41. This is a bigger issue for shippers wanting to understand the total costs of operating a pipeline. In Table 41, we use the same assumption of rate of return, taxes, and depreciation for all pipelines. The estimated ranges of pricing benchmarks for total costs in Table 41 come from simply switching between different choices of operating expenses and asset values reported under the Part 23 financial information framework.

    b. While the reporting of the RCM is useful for shippers to understand the past performance of a pipeline, it also contributes to the wide ranges of pricing benchmarks that can be calculated. The asset value under the RCM is sensitive to the inputs and assumptions that service providers employ. It is therefore particularly important that the underlying information and calculations are transparent, so that, if warranted, a prospective shipper could adjust the methodology.

208. Second, information reported under Part 23 is historical information, which might not reflect the expected future costs of operating pipeline services. We discuss the difference between Part 23 information, which consists of historical information, and the information fully regulated pipelines are required to disclose under Parts 8–12, which consists of both historical information and forecast, in section VII.

209. Third, the Part 23 financial information provides shippers with an understanding of the costs of operating a pipeline, but not the value of pipeline capacity. As explained in our framework in section III, the value of pipeline capacity is also an important consideration to a prospective shipper wanting to access the pipeline. It is not necessarily inconsistent with the outcome of

[181] National Gas Rules, Version 34, Part 23 – Access to non-scheme pipelines, 546(1).

a workably competitive market to see access prices exceed total costs (including a return of and on investment), for example, if the capacity of a pipeline is constrained. The Part 23 financial information does not provide for an understanding of the circumstances of a pipeline. For example, if a pipeline has been charging a high access price due to high demand of pipeline capacity, the RCM would imply a relatively low current asset value, which in turn suggests a relatively low cost-based pricing benchmark for total cost recovery, everything else equal. Such a cost-based benchmark, however, is unlikely to be informative to a prospective shipper wanting to compete for access to the pipeline.

210. As explained in our framework in section III, prices consistent with the outcome of a workably competitive market are not necessarily cost-based. However, in order for prospective shippers to get a good understanding of pipeline costs, information should be reported such that cost items can be easily identified and understood. In section VIII, we propose a number of recommendations to address some of the limitations of the Part 23 information summarised above.

C. Estimated cost of producing and using the Part 23 information

211. We were asked to assess the potential costs to pipeline service providers of producing the Part 23 financial information. We identify the costs of producing the Part 23 financial information as the time and effort required to (i) understand the AER Guideline, (ii) understand the AER Template, and (iii) collect and publish the information required by the AER Template. To understand the AER Guideline and Template presumably is a one-off task, while collecting and publishing the required information is required annually.

212. In the absence of direct survey information (ie, asking service providers about the costs they incurred), we rely on the "licence and regulatory costs" item reported in Table 2.1 of the AER Template as one estimate of compliance costs, realising that this item might not capture all of the costs of producing Part 23 information, and also might include other costs not associated with Part 23. We summarise "licence and regulatory costs" across pipelines in Table 46. Table 46 shows that for the period 1 January 2018 – 30 June 2018, "licence and regulatory costs" accounts for less than or around 1% of total costs excluding depreciation for most pipelines. For two pipelines, South East South Australia Pipeline and Tasmanian Gas Pipeline, "licence and regulatory costs" account for around 3% to 4% of total costs. The average "licence and regulatory costs" is AUD 77.3 thousand, and the total across all pipelines is more than AUD 1 million.

Table 46
Licence and regulatory costs for Part 23 pipelines

	Licence and regulatory costs in Table 2.1	Total costs less depreciation in Table 2.1	Licence and regulatory costs as a % of total costs less depreciation
	AUD thousands	AUD millions	%
	[A]	[B]	[C]
APA			
Berwyndale Wallumbilla Pipeline	9.1	1.5	0.6%
Goldfields Gas Pipeline	37.0	4.7	0.8%
Moomba to Sydney Pipeline	105.1	11.6	0.9%
South East South Australia Pipeline	13.6	0.4	3.4%
South West Queensland Pipeline	202.9	15.8	1.3%
Wallumbilla Gladstone Pipeline	25.9	107.0	0.0%
Jemena			
Darling Downs Pipeline	0.0	4.0	0.0%
Eastern Gas Pipeline	61.8	15.8	0.4%
Queensland Gas Pipeline	118.8	11.6	1.0%
VicHub Pipeline	0.0	0.1	0.0%
SEA Gas			
Port Campbell to Adelaide Pipeline	86.1	8.0	1.1%
Port Campbell to Iona Pipeline	0.3	0.2	0.1%
EPIC			
Moomba to Adelaide Pipeline System	162.9	13.6	1.2%
Palisade			
Tasmanian Gas Pipeline	258.4	5.8	4.4%
Summary			
Average	77.3	14.3	
Total	1,081.9	200.2	0.5%

Sources: Part 23 financial information, October 2018, Table 2.1.
Notes:
[A]: "Licence and regulatory costs" from Table 2.1 of the AER Template (1 January 2018 to 30 June 2018).
[B]: The sum of all costs reported in Table 2.1 except depreciation.
[C] = ([A] / 1,000) / [B] x 100

213. We were also asked to estimate the costs to shippers and others who wish to use the Part 23 financial information. Again, one way to identify these costs is to conduct a survey with the relevant stakeholders. In the absence of survey information, we report the time that we have spent during the project that resulted in this report to process and understand the Part 23 information. Part of our effort was spent on understanding the inconsistencies in the information reported across pipelines, which might not be of the same interest to all shippers that want to use the Part 23 financial information. Also, the cost of using the information in subsequent reporting periods is likely smaller than the first time this is done.

214. Altogether, we would expect that we spent more time understanding the Part 23 information than a shipper would if that shipper wanted to access one pipeline. Equally, it would not be reasonable to divide the total time by fourteen (for the fourteen pipelines) or by five (for the five service providers). Our discussion below uses a time of unit of working weeks or working days, with a working week consisting of five working days, each working day consisting of 7.6 hours.

215. Our analysis of the Part 23 information for the period 1 January 2018 – 30 June 2018 includes the following steps:

    a. Reviewing the AER Guideline, Explanatory Statement and Template.

    b. Reviewing the BoP reported by the different service providers and summarising any inconsistencies across the different BoP: this step and step a. informed our discussion in section IV.A.

    c. Compiling the information reported across different service providers. The AER Template consists of different tabs with different tables. Since we wanted to examine the same information items reported across different pipelines (eg, revenue or expenses), it was more efficient for us to compile all the reported information across the fourteen pipelines into a single workbook. To do this we first compiled all the information reported by a pipeline into a single table. We did not include the RCM and the WAP tables in this step since these two tables are different to the other tables in the AER Template and also vary across pipelines, making the information difficult to compile with the rest of the financial information. Our template for this step is illustrated in Appendix B – Summary template. After this step, for each pipeline we had three tables: (i) a summary table consisting of all information reported under the Part 23 financial information except the RCM table and the WAP table, (ii) the RCM table, and (iii) the WAP table. We then compiled these three tables across the fourteen pipelines into a single workbook. We used this workbook to produce all the calculations we document throughout this report.

    d. Using the workbook created in step c., we stepped through each "block" of reported information (eg, asset value under the depreciated book value method, revenue, expenses, etc.) to understand (i) how the reported information varies across pipelines, and (ii) to the extent that the same information item is required across different tables in the AER Template, how the information item might vary across these tables. For any inconsistency that we identified, we referred back to our summary in step a. and b. to understand what might explain the inconsistency. This step informed our discussion in section IV.B.

    e. Using our analysis in step d., we identified the different choices of information reported under Part 23 to use in our calculations of the pricing benchmarks. We also collected the standing prices reported by each pipeline. We summarised our pricing benchmark calculations in section V.

216. Our team consisted of four consultants working in parallel in some steps and sequentially in others. Steps a. and b. took approximately three and a half person-weeks. Step c. took one person-week. Step d. and e together took twelve person-weeks. Note that these estimates do not include the time it took us to write up and tabulate our analyses.

217. Again, the cost of providing and using the Part 23 financial information is likely higher the first time than in subsequent rounds of reporting. The above costs are presumably small relative to the revenue or payment associated with an access arrangement and the out-of-pocket costs associated with a commercial negotiation or an arbitration proceeding.

VII. A comparison of financial information disclosure under Part 23 and Parts 8–12

218. We were asked to compare information disclosure by uncovered pipelines under Part 23 with information disclosure by covered pipelines under Parts 8–12. The AER determines a forward-looking regulated access price for full-regulation covered pipelines, which it does not do for uncovered pipelines. We therefore expect there to be differences in the information disclosures. Nonetheless, shippers on both covered and uncovered pipelines are able to seek to agree negotiated access prices with service providers. We undertook the comparison between Part 23 and Parts 8–12 disclosures by reviewing the items of information disclosed under Part 23 and identifying the same information in the disclosures of covered pipelines. We also explored a reverse mapping. This section provides a comparison of the financial information pipeline service providers are required to report under Part 23 to that under Parts 8–12. Our Appendix C – Mapping Part 23 to Part 8 – 12 details our mapping of the information items under Part 23 to information disclosed by covered pipelines.

219. Fully regulated pipelines are required to submit an access arrangement proposal for the AER[182] to approve at the beginning of every regulatory period (typically every five years). The access arrangement determines the reference service and the corresponding reference tariff and non-tariff terms and conditions to access the reference service. The reference tariff is determined based on an assessment of the costs that an efficient service provider would incur in providing the reference service over the (future) regulatory period, and the service provider's expected cost of providing the reference service is an input for the regulator to determine efficient costs. The different cost components are set out in Part 9 of the NGR under the "building block approach". The different building blocks includes (i) a return on the projected capital base, (ii) depreciation of the projected capital base, (iii) the estimated cost of corporate income tax, (iv) any increments or decrements resulting from the operation

[182] The Economic Regulation Authority of Western Australia is responsible for regulating gas pipelines in Western Australia under the National Gas Rules. Elsewhere in Australia this is the responsibility of the Australian Energy Regulator.

of an incentive mechanism, and (v) a forecast of operating expenses.[183] Part 9 of the NGR prescribes the information that service providers must provide in support of each building block as well as sets out the requirements for allocating revenue between the reference service and non-reference services.

220. As an example of financial information reported under Part 9, we examine the access arrangement proposal for the Roma to Brisbane pipeline for the period 2017 to 2022 (submitted by APT Petroleum Pipelines Pty Limited (APTPPL)). As part of its access arrangement proposal, APTPPL submitted a range of information, including a "forecast operating expenses model", a "forecast capital expenditure model", and "post-tax revenue model" and a "transmission roll forward model". These models require various inputs, as listed in Appendix D—Part 8 – 12 Input lists.

221. For the comparison of the financial information reported under Part 9 to that reported under Part 23, we step through the different components of financial information Part 23 pipeline owners are required to report, and for each component, we identify whether, and to what extent, similar information was reported by APTPPL.

222. Part 23 pipeline owners are required to report: historical revenue, historical expenses, asset value (starting with the initial asset value, then historical additions, disposals and depreciation under the depreciated book value method and the RCM), the weighted average price of each service (unless exempt) and a standing price for pipeline services. Appendix C – Mapping Part 23 to Part 8 – 12 provides a summary of the disclosure requirements for these items under Part 23 and under Parts 8–12.

224. The AER states that "[t]he RCM asset valuation is intended to align with the building block approach applied to regulated pipelines…." [184] The RCM resembles the building block approach in that it determines the current asset value at any point in time by taking into account different cost components, including a return of and on capital and taxes. However, the building block approach under Part 9 uses projected capital expenditure and operating expenses for a future period of five years, while Part 23 only requires historical information. In particular:

    a. Part 23 pipeline owners report historical operating expenses in each year following the construction of the pipeline (within the RCM calculations), as well as a detailed breakdown of expenses for the reporting period 1 January 2018 – 30 June 2018 (in the "Statement of revenue and expenses"). APTPPL is required to report historical operating expenses for the ending regulatory period and forecast operating expenses for the commencing regulatory period.[185] Historical amounts are reported so that the

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183 National Gas Rules, Part 9, Division 3.

184 AER Explanatory Statement, p. 4.

185 APTPPL (2016), *Roma to Brisbane Access Arrangement proposal – Forecast operating expenditure model*, September 2016.

AER can use them to check whether the forecast of future operating expenses are reasonable.

b. Similarly, Part 23 pipeline owners report historical capital expenditure while APTPPL reports historical capital expenditure for the ending regulatory period and forecast capital expenditure for the commencing regulatory period.

225. Given its focus on future access prices, Part 9 does not require a reporting of current and historical information on, for example, revenue, volumes and pricing. Part 9 requires historical costs to be reported every five years because they are used as a cross-check of whether the forecasts of future costs (from which the regulated price will be calculated under Part 9) are reasonable. Part 23, on the other hand, requires that service providers report a full set of historical cost information every year.

a. The building block approach is used to determine the "Maximum Allowed Revenue" for the commencing regulatory period. The Maximum Allowed Revenue is not necessarily a good proxy for the actual revenue generated by fully regulated pipeline owners.[186] Under Rule 97(2) of Part 9 of the NGR, the formula that determines variation of a reference tariff in an access arrangement may provide for a revenue cap or a price cap. The Roma to Brisbane Pipeline access arrangement for 2017 to 2022 uses a price cap tariff variation mechanism,[187] and therefore, APTPPL has to report forecast volume for the commencing regulatory period.

b. Part 23 pipeline owners are required to report a detailed breakdown of revenue (for individual services provided) for the reporting period 1 January 2018 – 30 June 2018 and historical revenue in each year following the construction of the pipeline. Part 23 pipeline owners are also required to report weighted average prices for individual services provided (unless exempt) for the reporting period 1 January 2018 – 30 June 2018. For the calculation of weighted average prices, information on contracted capacity or actual volume is also reported.

226. The frequency and format of information reporting is another difference between Part 23 and Part 9 financial information.

a. Part 23 financial information is reported on an annual basis, allowing shippers to obtain information such as actual revenue, operating expenses and capital expenditure annually. In addition, given the format in which Part 23 historical information is reported, shippers can see the full time series of historical revenue, capital expenditure

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[186] In the case of the Roma to Brisbane Pipeline's 2017-2022 access arrangement, APTPPL is required to rebate 70% of revenue it earns from rebateable services to shippers who are contracting reference services. Therefore, APTPPL is required to report on the revenue it has earned during the prior calendar year for the rebateable services (park and loan services, in-pipe trading services and capacity trading services). See AER, Roma to Brisbane Gas Pipeline Access Arrangement 2017–22, 2017, fn 14, p. 17; APA, Roma to Brisbane Pipeline – Notification of annual tariff variation, April 2018.

[187] AER, Roma to Brisbane Pipeline Gas Access Arrangement 2017–22, 2017, s 2.1.5, p. 20.

and operating expenses since the construction of the pipeline within the same workbook.

b. Fully regulated pipelines disclose financial information during the regulatory process that precedes the beginning of every regulatory period, and therefore, to the extent that information about actual operating expenses or capital expenditure is reported, shippers only obtain such information every regulatory period (typically five years). There is no centralised source of historical information for fully regulated pipelines. To obtain all available historical information for a fully regulated pipeline, shippers would need to compile information disclosures across multiple access arrangements.

227. The difference in the format of information reporting also means that shippers can obtain the construction cost (to the extent that Part 23 pipeline owners report actual construction cost) and historical capital expenditure for Part 23 pipelines within the same workbook. This is not as straightforward for fully regulated pipelines since (i) actual capital expenditure is only reported every five years and (ii) from one regulatory period to the next, the asset value is indexed for inflation, so the initial asset value[188] can only be obtained by looking at the access arrangement when a pipeline first became regulated.

228. The building block approach requires fully regulated pipeline owners to estimate the projected return of and on capital as well as tax liabilities for the commencing regulatory period. Part 23 pipeline owners are required to report similar information, although only historical numbers. Additionally, the differences in the nature of the reported information and in the method of estimation make it difficult to compare these components across the two frameworks.

a. The return on capital for fully regulated pipelines is calculated based on a method determined by the AER to estimate the return on capital for the next five years of the regulatory period. It appears that many Part 23 pipeline owners use a framework similar to that of the AER to estimate their return on capital. However, the reported information under Part 23 is historical rather than projected, and while Part 23 pipeline owners are required to explain their methodology to estimate the return on capital, the exact rate of return that a pipeline owner applies is not reported (but may be inferred).

b. Fully regulated pipelines report straight-line depreciation for every year of the ending and commencing regulatory period. Part 23 pipeline owners only report cumulative straight-line depreciation (since the construction or acquisition of the pipeline, in the

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[188] Under Part 9 of the National Gas Rules, Division 4, s 77, the method used to calculate the initial opening capital base when a pipeline first becomes a covered pipeline depends on whether the pipeline was commissioned before or after the commencement of the National Gas Rules. If the pipeline was commissioned after the commencement of the rules, it equals the cost of construction of the pipeline plus capex, minus depreciation and disposals since the commissioning of the pipeline. If the pipeline was commissioned before the commencement of the rules, the opening capital base is determined by reference to the relevant provisions of the Gas Code, typically through a regulatory process.

"Statement of assets") and straight-line depreciation in the reporting period 1 January 2018 – 30 June 2018 (in the "Statement of revenue and expenses"). The RCM provides an estimate of depreciation on an annual basis. However, depreciation under the RCM is a residual estimate and does not reflect actual depreciation of the pipeline assets.

c. Part 23 pipelines have the option to estimate taxes using either a pre-tax commercial rate of return or a post-tax approach.[189] All pipeline owners reported their estimated tax liabilities for every year since the construction of the pipeline using the post-tax approach. However, as detailed above, the assumptions underlying different service providers' calculations are different. For fully regulated pipelines tax liabilities have been estimated using the tax building block. The tax building block forecasts tax costs for a benchmark entity using a standard tax calculation that has regard to estimates of taxable revenue, tax expenses (depreciation, interest, operating expenses) and the statutory corporate income tax rate.[190] The AER recently introduced some changes in order to (i) recognise the ability to immediately expense some capex and (ii) use the diminishing value (DV) method to estimate tax depreciation for new assets.[191] The AER states that the DV reflects the practice used by other non-National Tax Equivalent Regime entities and allows for faster and earlier tax depreciation (ie, less tax over the life of the asset in NPV terms).[192]

VIII. Recommendations

229. Based on our analysis of the reported financial information under Part 23, we propose a number of recommendations in this section.

230. Our report highlights several inconsistencies in the reporting of financial information by non-scheme pipelines. Our recommendations therefore focus on additions or changes to the AER Template and Guideline to improve the consistency, clarity and usability of the reported information and to assist shippers in identifying useful information.

231. As we noted above, given the nature of pipeline operations, it is to be expected that a range of cost-based pricing benchmarks will be wide. Our recommendations do not aim at narrowing this range.

232. To explain the reasons for the recommendations in this section, we reiterate the inconsistencies documented in the previous sections. While some of the inconsistencies might not substantially alter the calculations of cost-based pricing benchmarks with the financial information disclosed to date, this may not remain the case in the future.

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189 AER Explanatory Statement, p. 25.

190 AER, Final report – Review of regulatory tax approach, 2018, p. 21.

191 AER, Final report – Review of regulatory tax approach, 2018, p. 3.

192 AER, Final report – Review of regulatory tax approach, 2018, p. 71.

Furthermore, the significance of the inconsistencies will depend on exactly how the information is used, and, as we have explained, there are many different ways in which pricing benchmarks can be derived. We therefore recommend that the AER reviews these inconsistencies and considers whether additions or changes to the Guideline and the Template would be valuable.

233. We recommend that the AER creates a template structure for the BoP. For example, the AER can specify section and subsection headings in a template so that the same topics can be covered in the same section by all service providers. We understand that the purpose of the BoP is to document the service providers' assumptions, methods, inputs and sources of information and calculations. This information varies across pipelines, which means that some service providers need to include more or less information in the BoP than others. However, the BoP disclosed by service providers so far takes different formats, which makes it difficult to efficiently extract the relevant information.[193] We think that it should be possible to create a template structure for the BoP that (i) facilitates identifying where a service provider is following the AER Guideline and where it is not, and (ii) ensures that the BoP provides an explanation in circumstances where a service provider deviates from the Guideline.[194]

234. We recommend that the AER be consistent in the labelling of the information in its Template.

    a. First, if the same field of information is required across different tables in the Template, its label should be the same. For example, it is unclear to us whether the item "total costs" excluding depreciation based on the "Statement of revenue and expenses" conveys the same information as "operating expenses" reported in the RCM. Our analysis in Table 17 indicates that for some pipelines the average historical "operating expenses" can be very different in magnitude to "total costs" excluding depreciation.

    b. Second, it would be helpful if tables that support information in other tables, such as the "Depreciation" tab and the "Statements of pipeline assets" tab, were consistently

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[193] Take for example the BoP of Jemena versus that of APA. In its BoP, APA provides different sections to discuss pipeline-specific information, pipeline financial information, asset value under the RCM and WAP. APA also only provides one BoP for all of its pipelines, and it uses the pipeline-specific information section to discuss any differences in the information reporting of its pipelines. Jemena uses a table format where it steps through individual tables in the AER Template, and for each table Jemena provides a set of "base information" such as the specific line item description, source, methodology, and assumptions used in producing the item. While the format adopted by Jemena appears more structured, it is more difficult to read and follow. Jemena reports a different BoP for each of its pipeline, and it is difficult to identify where the information reporting might be different across the different Jemena pipelines.

[194] For example, currently some service providers report ranges of asset lives that differ from those provided for in the AER Guideline; however, these service providers do not provide a clear explanation for why this is the case in their BoP.

structured. As we detailed in section IV.B, it is unclear to us (i) why the two tables 3.3.1 and 3.3.2 for "fixed assets at cost" and "shared assets at cost", respectively, do not have the same fields (eg, Table 3.3.1 has two depreciation columns while Table 3.3.2 only has one), (ii) why there are two tables in the first place when the pre-populated options for the asset category in the "fixed assets at cost" table already include "shared supporting assets",[195] (iii) why the different asset categories in Table 3.1 are reported differently, with some having construction cost or purchase cost, additions, disposals and closing value, and others having only some but not all of these components, and (iv) why different terms such as "initial construction costs", "initial purchase costs", "initial purchase/improvement cost", "shared property, plant and equipment at cost", "construction or acquisition cost" are used in different places and for different asset categories in Table 3.1 and Table 3.3.

235. The inconsistencies in the reported information partly result from service providers (i) adding additional information to the AER Template and/or (ii) including different information to other service providers under the same line item. We recommend that the AER review these inconsistencies and revise the degree of disaggregation of information in its Template accordingly.

    a. We recommend that, where the AER allows for additional information to be added to its Template or where service providers are allowed to deviate from the AER Guideline such as the asset life reporting, the AER (i) introduces explicit yes/no fields such as "is the information reported consistent with the AER Guideline" with specific reference to the section in the Guideline or "are additional fields added to this table", and (ii) adds a field for the service provider to provide reference to the BoP for an explanation if the answer from a service provider is such that it adds information to the Template or deviates from the Guideline. This ensures that service providers attempt to provide clarity to the reporting information when it is required.

    b. We recommend that the AER asks service providers to provide details explaining "catch-all" items such as "other shared costs", "other assets", and "other direct costs". The explanations in the BoP and reporting of these items in the Template should be sufficiently clear for shippers to (i) understand what the items comprise and (ii) identify the magnitude of the individual components that make up the majority (eg, 80%) of the "catch-all" items. When service providers explain in their BoP particular

[195] In Tables 3.3.1 and 3.3.2, service providers are required to report information related to the depreciated book value method for individual asset categories. The AER provides a list of asset categories that the service providers can choose from in a drop-down menu in each row. The asset category options in Table 3.3.1 are "Pipelines", "Compressors", "City Gates, supply regulators and valve stations", "Metering", "Odourant plants", "SCADA (Communications)", "Buildings", "Land and easements", "Other depreciable pipeline assets", and "Shared supporting assets". The asset category options in Table 3.3.2 are "Property plant and equipment", "Inventories", "Deferred tax assets", and "Other assets".

information items that do not appear in the Template,[196] we recommend that the AER require service providers to explain how shippers can identify the information in the Template. We think that introducing a template BoP that maps with key "blocks" of information in the AER Template could help to ensure that service providers provide these explanations. Additionally, adding a field in the Template where these "catch-all" items are reported to require service providers to reference where in their BoP the explanations are provided will also be useful.

c. If a service provider includes any adjustment to a recorded figure,[197] we recommend that the AER requires that the service provider discloses the magnitude of the adjustments.

236. We recommend that the AER add additional fields to "reconcile" the information reported in the depreciated book value method and the RCM.

a. First, it will be useful if service providers explain whether they acquired or constructed the pipeline and when, and the starting time of their reporting under both methods (ie, column "acquisition date" in Table 3.3 and the first year of reporting in Table 4.1). If a service provider acquired a pipeline, it would be useful to know the value of the transaction and the value of shipper contracts purchased along with the purchase of the pipeline. That is, it would be useful to have both the book value at the time of acquisition and the acquisition value reported.

b. Where the sum of "construction or acquisition costs" in Table 3.3 is different from the first value of construction cost in Table 4.1, service providers should indicate why this is the case, ie, whether this is driven by the use of construction cost under the RCM versus the use of acquisition cost under the depreciated book value method.

c. The inconsistency in the reporting of capital expenditure between the two methods, as we highlight in paragraph 137, also needs to be explained.

237. We recommend that the AER asks for more clarity in the calculations of the RCM.

a. The calculations of the "return on capital" component in Table 4.1 should be reported. This means service providers will need to report their assumed rate of return on investment for every year, and show their calculation steps of the dollar amount "return on capital" using the assumed rate of return.

b. The calculations of "net tax liabilities" should be reported. Currently, service providers explain their estimation in the BoP. However, information in the BoP is insufficient for shippers to understand how the reported figures are calculated. In general, the post-tax approach (i) starts with revenue, (ii) subtracts operating expenses, (iii) subtracts

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[196] For example, in the case of "other attributable costs" discussed by APA. See APA Basis of Preparation, p. 9.

[197] For example, "other direct costs" reported by APA or the calculation of "gross capex" by Jemena.

interest expenses, (iv) subtracts tax depreciation, and then (v) multiplies by the prevailing tax rate, which we think is feasible to be reported as part of the Part 23 financial information. It might also be useful for the AER to provide more guidance on how it thinks the tax liabilities should be estimated.

c. To avoid confusion and inconsistencies across service providers, we recommend that the AER provides an example table with all calculations provided for the RCM. Within the example table, the AER should specify for each field the exact timing for which or the nature of which the information should be reported. For example, is the capital expenditure for a reporting period the as-incurred amount, or should there be any timing adjustment to the as-incurred amount?

238. The RCM methodology in the AER Guideline seems to assume that capex occurs at the end of the reporting period, since the return during the reporting period takes into account only the opening asset value: "the rate of return to be applied to the closing value of the capital base from the immediately preceding year".[198] The AER could consider adopting a different assumption, for example a mid-year convention.

239. As we explain above, the Part 23 financial information focuses on historical information and does not require any projections of the future by service providers. This means any cost-based pricing benchmarks cannot take into account future expected investment costs of a pipeline. This also means information about the circumstances of the pipeline, such as whether its capacity is constrained and future expansion is required is not required to be published. It might be helpful if pipelines were required to indicate whether expected future capital maintenance requirements are likely to be in line with, significantly above or significantly below recent history. We suggest the service providers should report the amount of available capacity.

240. Since it is useful to be able to compare information across pipelines, we recommend that the AER asks service providers to produce certain summary information.

a. We think a template similar in nature to our summary template in Appendix B – Summary table should be included at the beginning of each reporting workbook. We recognise that for a shipper to use information reported by a pipeline, it is easier to use the different tables in the separate tabs of the AER Template. However, adding a summary table that comprises of all the required information (other than the RCM table and the WAP table) does not create significant additional burden and will make it easier to compare information across pipelines. It is more efficient for service providers to report the summary table than for others to create the summary table themselves. Provided that the labelling of information is revised so that the same information appearing in different tables is labelled consistently, having a summary table in the Template will assist with consistency within each pipeline's disclosure, because the summary table can serve as the common "source" for the other tables. We

[198] AER Guideline, p. 20.

also recommend that when the same information is reported across the different tables, including the summary table, that the information is linked and not hard-coded. Similarly, if a line item is calculated from other line items, the calculation should be shown in Excel formulas, as opposed to hard-coded.

b. We recommend that the AER include in the Template certain summary fields, such as the proportion of shared assets to total assets, shared costs to total costs, ratio of current asset value between the RCM and the depreciated book value method, etc. These summary fields are unlikely to add extra burden to service providers, but will be helpful for shippers to quickly identify areas where a pipeline might be different from the other pipelines. These summary tables can include the "catch-all" items mentioned in paragraph 235.b. These statistics can then be used in conjunction with some thresholds such as "if an item exceeds a certain percentage of the total (total costs, assets etc.)" to require service providers to provide further explanations in their BoP.

c. As noted in section IV.A, even though the AER Guideline requires that service providers disclose "the numeric quantity or percentage of the allocator to be applied for each cost item [or each revenue item, or each asset or liability], including an explanation of how the numeric quantity or percentage has been calculated"[199] for shared costs and shared assets, not all service providers do so. We recommend that these statistics be added to the Template.

[199] AER Guideline, pp. 15-16.

Appendix A—Documents cited

A. AER and ERA determinations

Table 47
List of regulatory determinations included in sample to calculate regulatory rates of return

Source	Entity	Type	Regulator	First year of regulatory period	Regulatory period
[1]	ActewAGL	Electricity distribution	AER	2010	2010 - 2014
[2]	ActewAGL		AER	2015	2015 - 2019
[3]	Amadeus Gas Pipeline	Gas transmission	AER	2012	2012 - 2016
[4]	Amadeus Gas Pipeline		AER	2017	2017 - 2021
[5]	Ausgrid	Electricity distribution	AER	2010	2010 - 2014
[6]	Ausgrid		AER	2015	2015 - 2019
[7]	Dampier Bunbury Natural Gas Pipeline	Gas transmission	ERA (WA)	2011	2011 - 2015
[8]	Dampier Bunbury Natural Gas Pipeline		ERA (WA)	2016	2016 - 2020
[9]	Directlink	Electricity transmission	AER	2007	2007 - 2015
[10]	Directlink		AER	2016	2016 - 2020
[11]	Energex	Electricity distribution	AER	2011	2011 - 2015
[12]	Energex		AER	2016	2016 - 2020
[13]	GasNet, Victorian Transmission System	Gas transmission	AER	2014	2014 - 2017
[14]	GasNet, Victorian Transmission System		AER	2018	2018 - 2022
[15]	Goldfields Gas Pipeline	Gas transmission	ERA (WA)	2010	2010 - 2014
[16]	Goldfields Gas Pipeline		ERA (WA)	2015	2015 - 2019
[17]	Mid-West and South-West Gas Distribution Systems	Gas distribution	ERA (WA)	2010	2010 - 2014
[18]	Mid-West and South-West Gas Distribution Systems		ERA (WA)	2015	2015 - 2019
[19]	Roma to Brisbane Pipeline	Gas transmission	AER	2012	2013 - 2017
[20]	Roma to Brisbane Pipeline		AER	2018	2018 - 2022
[21]	SA Power Networks	Electricity distribution	AER	2011	2011 - 2015
[22]	SA Power Networks		AER	2016	2016 - 2020
[23]	TasNetworks (Transend)	Electricity transmission	AER	2010	2010 - 2014
[24]	TasNetworks (Transend)		AER	2016	2016 - 2019
[25]	TransGrid	Electricity transmission	AER	2010	2010 - 2015
[26]	TransGrid		AER	2015	2015 - 2018

Note that where a regulatory period is defined in terms of financial year, the above table takes the first year of the regulatory period as the calendar year coinciding with the first financial year. For example, the second TasNetworks determination used in this sample covers the regulatory period FY 2015-16 to FY 2018-19, so the first year listed above is 2016 and the regulatory period listed above is 2016 – 2019. This in effect marginally delays when some determinations affect the regulatory mean rate of return that we calculate for each year.

Table 47 includes the following determinations:

[1]: AER (2015), "Final Decision - ActewAGL distribution determination 2015-16 to 2018-19", April 2015.

[2]: AER (2015), "Final Decision - ActewAGL distribution determination 2015-16 to 2018-19", April 2015.

[3]: AER (2011), "N.T. Gas Access arrangement proposal for the Amadeus Gas Pipeline, 1 August 2011 - 30 June 2016", July 2011.

[4]: AER (2016), "FINAL DECISION Amadeus Gas Pipeline Access Arrangement 2016 to 2021 Overview", May 2016.

[5]: AER (2015), "Final Decision - Ausgrid distribution determination 2015-16 to 2018-19", April 2015.

[6]: AER (2015), "Final Decision - Ausgrid distribution determination 2015-16 to 2018-19", April 2015.

[7]: ERA WA (2012), "Access arrangement information for the Dampier to Bunbury Natural Gas Pipeline", October 2012.

[8]: ERA WA (2016), "Final decision on proposed revisions to the access arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016-2020", June 2016.

[9]: AER (2015), "Final Decision - Directlink transmission determination 2015-16 to 2019-20", April 2015.

[10]: AER (2015), "Final Decision - Directlink transmission determination 2015-16 to 2019-20", April 2015.

[11]: AER (2010), "Energex - Distribution determination 2010-11 to 2014-15", May 2010.

[12]: AER (2015), "Final Decision - Energex determination 2015-16 to 2019-20", October 2015.

[13]: APA GasNet Australia (2013), "Access Arrangement Information Effective 1 July 2013 - 31 December 2017", November 2013.

[14]: AER (2017), "FINAL DECISION APA VTS Australia Gas access arrangement 20187 to 2022 Overview", November 2017.

[15]: GGT (2012), "Proposed revisions to access arrangement information (as approved by ERA 5 August 2010)", March 2012.

[16]: ERA WA (2016), "Access arrangement information for the Goldfields Gas Pipelines", July 2016.

[17]: ERA WA (2011), "Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems", February 2011.

[18]: ERA WA (2015), "Final decision on proposed revisions to the access arrangement for the Mid-West and South-West Gas Distribution Systems", September 2015.

[19]: AER (2012), "APT Petroleum Pipeline Pty Ltd Access arrangement final decision Roma to Brisbane Pipeline 2012-13 to 2016-17", August 2012.

[20]: AER (2017), "FINAL DECISION Roma to Brisbane Gas Pipeline Access Arrangement 2017-22 Overview", November 2017.

[21]: AER (2010), "South Australia distribution determination 2010-11 to 2014-15", May 2010.

[22]: AER (2015), "Final Decision - SA Power Networks determination 2015-16 to 2019-20", October 2015.

[23]: AER (2009), "Statement on updates for Transend transmission determination", November 2009.

[24]: AER (2015), "Final Decision - TasNetworks transmission determination 2015-16 to 2018-19", April 2015; AER (2015), "Rate of return fact sheet", April 2015.

[25]: AER (2015), "Final Decision - TransGrid transmission determination 2015-16 to 2017-18", June 2015.

[26]: AER (2015), "Final Decision - TransGrid transmission determination 2015-16 to 2017-18", June 2015.

B. Sources of standing price information

Table 48
List of sources of standing price information

Row	Pipeline	Source
[1]	APA pipelines	APA (2018), Current tariffs and terms, July 2018.
[2]	Darling Downs Pipeline	Jemena (2019), Darling Downs Pipeline transportation tariffs effective 1st January 2019, January 2019.
[3]	Eastern Gas Pipeline	Jemena (2019), Eastern Gas Pipeline transportation tariffs effective 1st January 2019, January 2019.
[4]	Queensland Gas Pipeline	Jemena (2019), Queensland Gas Pipeline transportation tariffs effective 1st January 2019, January 2019.
[5]	VicHub Pipeline	Jemena (2019), VicHub Pipeline transportation tariffs effective 1st January 2019, January 2019.
[6]	SEA Gas pipelines	SEA Gas (2019), Access to Services.
[7]	Moomba to Adelaide Pipeline System	EPIC (2018), Moomba to Adelaide Pipeline System Standing price information, January 2018.
[8]	Tasmanian Gas Pipeline	Palisade (2018), Part 23 User Access Guide, December 2018.

C. Sources of nameplate capacity information

Table 49
List of sources of nameplate capacity information

Row	Pipeline	Source
[1]	**APA**	
[2]	Berwyndale Wallumbilla Pipeline	APA (2018), Berwyndale Wallumbilla Pipeline schematic, April 2018.
[3]	Goldfields Gas Pipeline	APA (2018), Goldfields Gas Pipeline schematic, June 2018.
[4]	Moomba to Sydney Pipeline	APA (2018), Moomba Sydney Pipeline schematic, April 2018.
[5]	South East South Australia Pipeline	APA (2018), South East South Australia Pipeline schematic, April 2018.
[6]	South West Queensland Pipeline	APA (2018), South West Queensland Pipeline schematic, May 2018.
[7]	Wallumbilla Gladstone Pipeline	APA (2018), Wallumbilla Gladstone Pipeline schematic, April 2018.
[8]	**Jemena**	
[9]	Darling Downs Pipeline	Jemena (2019), Darling Downs Pipeline schematic, April 2019.
[10]	Eastern Gas Pipeline	Jemena (2019), Eastern Gas Pipeline schematic, April 2019.
[11]	Queensland Gas Pipeline	Jemena (2019), Queensland Gas Pipeline schematic, April 2019.
[12]	VicHub Pipeline	Jemena (2019), VicHub Pipeline schematic, April 2019.
[13]	**SEA Gas**	
[14]	All pipelines	SEA Gas (2019), Services - Maps, January 2019.
[15]	**EPIC**	
[16]	Moomba to Adelaide Pipeline System	EPIC (2019), MAPS Operational Information Summary, April 2019.
[17]	**Palisade**	
[18]	Tasmanian Gas Pipeline	TGP (2018), Pipeline Information, May 2019.

D. Others

Table 50
List of other documents cited

	Document Title
Academic articles, textbooks and conference notes	
[1]	Delp, A.B. & John W. Mayo (2017), "The evolution of "competition": Lessons for 21st century telecommunications policy", *Review of Industrial Organization* , 50(4), 393-416.
[2]	Biggar, D. (2001), "Access pricing and competition", Australian Competition and Consumer Commission 2001 Conference on Regulation and Investment, Sydney, Autralia, 26-27 March 2001.
[3]	Biggar, D. (2009), "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?", Review of Network Economics, 8(2), 128-152.
[4]	Carpenter, P.R & Carlos Lapuerta, "Asset Valuation and the Pricing of Monopoly Infrastructure Services: A Discussion Paper", The Brattle Group, July 2000.
[5]	Demsetz, H. (1968), "Why Regulate Utilities?", Journal of Law and Economics, 11(1), 55-65.
[6]	Marshall, A. (1895), "Chapter IV: Law of demand continued, elasticity of demand" in *Principles of Economics* (pp. 178-192), London:MacMillan and Co., p. 178.
[7]	Myers, S.C. (1972), "The Application of Finance Theory to Public Utility Rate Cases", Bell Journal of Economics and Management Science, 3(2), 58-97.
[8]	Shogren, R. (2004), "Dynamic Efficiencies and Workable/Effective Competition – Comments on a Paper by William G. Shepherd", Australian Competition and Consumer Commission 2004 Regulatory Conference, Gold Coast, Australia, 29 July 2004.
[9]	Tirole, J. (1988), "Price Discrimination" in *The Theory of Industrial Organization* (pp. 133-168), Cambridge, MA: MIT.

	Document Title

Other public sources

[1] ACCC,"AA proposed by EPIC Energy for the MAPS - Final Decision", September 2001.
[2] ACCC, “Adequacy of weighted average price information – ACCC recommendations”.
[3] AEMC, National Gas Amendment (Regulation of covered pipelines) Rule 2019, March 2019.
[4] AER, Financial Reporting Guideline for Non-Scheme Pipelines Explanatory Statement, December 2017.
[5] AER, Financial Reporting Guideline for Non-Scheme Pipelines, December 2017.
[6] AER, Roma to Brisbane Gas Pipeline Access Arrangement 2017-22, November 2017.
[7] AER, "Rate of return instrument", December 2018.
[8] AER, Final report – Review of regulatory tax approach, December 2018.
[9] AER, Non-scheme Financial Reporting Template, August 2018.
[10] APA - FY 2015 Financial report, August 2015.
[11] APA, Berwyndale Wallumbilla Pipeline Part 23 financial information, June 2018.
[12] APA, Moomba to Sydney Pipeline Part 23 financial information, June 2018.
[13] APA, Roma to Brisbane Pipeline – Notification of annual tariff variation, April 2018.
[14] APA Basis of Preparation, October 2018.
[15] APTPPL, Roma to Brisbane Access Arrangement proposal – Forecast operating expenditure model, September 2016.
[16] Australian Competition and Consumer Commission, "Inquiry into the east coast gas market", April 2016.
[17] EPIC Basis of Preparation - Moomba to Adelaide Pipeline System, October 2018.
[18] Gas Market Reform Group, "Gas Pipeline Information Disclosure and Arbitration Framework - Final Design Recommendation", June 2017.
[19] Jemena Basis of Preparation - Darling Downs Pipeline, October 2018.
[20] Jemena Basis of Preparation - Eastern Gas Pipeline, October 2018.
[21] Jemena Basis of Preparation - Queensland Gas Pipeline, October 2018.
[22] Jemena Basis of Preparation - VicHub, October 2018.
[23] National Gas (South Australia) Act 2008, December 2018.
[24] National Gas Rules Version 44 - Part 9, March 2019.
[25] National Gas Rules, Version 34, Part 23, October 2017.
[26] Palisade, Tasmanian Gas Pipeline Part 23 financial information, June 2018.
[27] Palisade Basis of Preparation – Tasmanian Gas Pipeline, October 2018.
[28] Productivity Commission, "Review of the Gas Access Regime", Inquiry Report No. 31, June 2004.
[29] Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Lts & Anor [2002] WASCA 231.
[30] SEA Gas Basis of Preparation, October 2018.
[31] The National Gas (Pipelines Access Arbitration) Amendment Rule 2017.
[32] Vertigan, M., "Examination of the current test for the regulation of gas pipelines", December 2016.

Appendix B—Summary template

Example summary: Part 23 financial information for Berwyndale Wallumbilla Pipeline, owned by APA

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[1]	Pipeline name		Berwyndale Wallumbilla Pipeline			
[2]	Pipeline owner		APA			
[3]	TBG reference		BWP			
[4]	1. Pipeline information					
[5]	Pipeline location	Table 1.1	Queensland			
[6]	Pipeline length (km)	Table 1.1	112			
[7]	Number of customers	Table 1.1	3			
[8]	Service type	Table 1.1	Transmission			
[9]	Transportation services	Table 1.2	Parent category of [10], [11] and [12].			TBG entry.
[10]	Firm transportation service	Table 1.2	Yes			To non-related parties.
[11]	Interruptible or as available transportation service	Table 1.2	Yes			To non-related parties.
[12]	Backhaul services	Table 1.2	No			To non-related parties.
[13]	Stand-alone compression services	Table 1.2	Parent category of [14] and [15].			TBG entry.
[14]	Firm compression service	Table 1.2	No			To non-related parties.
[15]	Interruptible compression service	Table 1.2	No			To non-related parties.
[16]	Storage services	Table 1.2	Parent category of [17] and [18].			TBG entry.
[17]	Park services	Table 1.2	No			To non-related parties.
[18]	Park and loan services	Table 1.2	No			To non-related parties.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[19]	Trading services	Table 1.2	Parent category of [20] and [21].			TBG entry.
[20]	Capacity trading service	Table 1.2	No			To non-related parties.
[21]	In pipe trading service	Table 1.2	Yes			To non-related parties.
[22]	Other (please specify)	Table 1.2	Parent category of [23] to [28].			TBG entry.
[23]	Redirection service	Table 1.2				
[24]	Other - Delivery Point Charge	Table 1.2				
[25]	Other - Administration and Maintenance Charge	Table 1.2				
[26]	Other - Establishment Charges	Table 1.2				
[27]	Other - Overun Charge	Table 1.2				
[28]	Other - Nomination Variation Charge	Table 1.2				
[29]	Other - Enhanced MHQ Service Charge	Table 1.2				
[30]	Other - Capacity Charge	Table 1.2				
[31]	1.1 Financial performance					
[32]	Earnings before interest and tax	Table 1.1.1	4,732,929.9			
[33]	Total assets	Table 1.1.1	84,693,557.9			
[34]	Return on assets	Table 1.1.1	5.59%			
[35]	2. Revenues and expenses					
[36]	Direct revenue	Table 2.1				May include related party transactions.
[37]	Total service revenue	Table 2.1	6,822,473.2	6,822,473.2	0.0	May include related party transactions.
[38]	Other direct revenue	Table 2.1	0.0	0.0	0.0	May include related party transactions.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[39]	Total direct revenue	Table 2.1	6,822,473.2	6,822,473.2	0.0	May include related party transactions.
[40]	Indirect revenue allocated	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[41]	Other revenue	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[42]	Total indirect revenue allocated	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[43]	Total revenue	Table 2.1	6,822,473.2	6,822,473.2	0.0	May include related party transactions.
[44]	Direct costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[45]	Repairs and maintenance	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[46]	Wages	Table 2.1	-481,441.9	-481,441.9	0.0	May include related party transactions.
[47]	Depreciation	Table 2.1	-579,526.2	-579,526.2	0.0	May include related party transactions.
[48]	Insurance	Table 2.1	-8,941.1	-8,941.1	0.0	May include related party transactions.
[49]	Licence and regulatory costs	Table 2.1	-9,143.1	-9,143.1	0.0	May include related party transactions.
[50]	Directly attributable finance charges	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[51]	Leasing and rental costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[52]	Other direct costs	Table 2.1	-241,741.0	-241,741.0	0.0	May include related party transactions.
[53]	Total direct costs	Table 2.1	-1,320,793.3	-1,320,793.3	0.0	May include related party transactions.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[54]	Shared costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[55]	Employee costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[56]	Information technology and communication costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[57]	Indirect operating Expenses	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[58]	Shared asset depreciation	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[59]	Rental and leasing costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[60]	Borrowing costs	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[61]	Loss from sale of shared fixed assets	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[62]	Impairment Losses (nature of the impairment loss)	Table 2.1	0.0	0.0	0.0	May include related party transactions.
[63]	Other shared costs	Table 2.1	-768,750.0	-768,750.0	0.0	May include related party transactions.
[64]	Total shared costs allocated	Table 2.1	-768,750.0	-768,750.0	0.0	May include related party transactions.
[65]	Total costs	Table 2.1	-2,089,543.3	-2,089,543.3	0.0	May include related party transactions.
[66]	Earnings before Interest and tax (EBIT)	Table 2.1	4,732,929.9	4,732,929.9	0.0	May include related party transactions.

[67] 2.1 Revenue by service

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[68]	Direct revenue	Table 2.1.1				May include related party transactions.
[69]	Firm forward haul transportation services	Table 2.1.1	6,787,806.5	6,787,806.5	0.0	May include related party transactions.
[70]	Interruptible or as available transportation services	Table 2.1.1	29,421.2	29,421.2	0.0	May include related party transactions.
[71]	Backhaul services	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[72]	Firm stand-alone compression service	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[73]	Interruptible or as available stand-alone compression service	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[74]	Park and park and loan services	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[75]	Capacity trading service	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[76]	In pipe trading service	Table 2.1.1	5,245.5	5,245.5	0.0	May include related party transactions.
[77]	Distribution/transmission revenue	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[78]	Customer contribution revenue	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[79]	Profit from sale of fixed assets	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[80]	Other direct revenue	Table 2.1.1	0.0	0.0	0.0	May include related party transactions.
[81]	Total direct revenue	Table 2.1.1	6,822,473.2	6,822,473.2	0.0	May include related party transactions.
[82]	2.2 Revenue contributions					

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[83]	Customer contributions	Table 2.2.1	0.0	0.0	0.0	May include related party transactions.
[84]	Government contributions	Table 2.2.2	0.0			
[85]	2.3 Indirect revenue					
[86]	Mortlake O&M Services - Indirect revenue	Table 2.3.1	0.0			May include related party transactions.
[87]	Mortlake O&M Services - % allocated to pipeline	Table 2.3.1				
[88]	2.4 Shared costs					
[89]	Employee costs - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[90]	Information technology and communication costs - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[91]	Indirect operating Expenses - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[92]	Shared asset depreciation - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[93]	Rental and leasing costs - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[94]	Borrowing costs - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[95]	Loss from sale of shared fixed assets - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[96]	Impairment Losses (nature of the impairment loss) - Shared costs	Table 2.4.1	0.0	0.0	0.0	May include related party transactions.
[97]	Other shared costs - Shared costs	Table 2.4.1	-768,750.0	-768,750.0	0.0	May include related party transactions.
[98]	Finance - Shared costs	Table 2.4.1	-90,504.6	-90,504.6	0.0	May include related party transactions.
[99]	Information and Communication Technology - Shared costs	Table 2.4.1	-182,625.3	-182,625.3	0.0	May include related party transactions.
[100]	Information & Communcations Systems - Shared costs	Table 2.4.1	0.0			
[101]	Administration and Executive - Shared costs	Table 2.4.1	-224,106.5	-224,106.5	0.0	May include related party transactions.
[102]	Business and Planning (External Relations) - Shared costs	Table 2.4.1	-42,289.3	-42,289.3	0.0	May include related party transactions.
[103]	External Relations - Shared costs	Table 2.4.1	0.0			
[104]	Legal Counse/Company Secretary - Shared costs	Table 2.4.1	-79,460.8	-79,460.8	0.0	May include related party transactions.
[105]	Legal & Corporate Affairs - Shared costs	Table 2.4.1	0.0			
[106]	Contract Management - Shared costs	Table 2.4.1	-59,258.9	-59,258.9	0.0	May include related party transactions.
[107]	Regulatory Strategy - Shared costs	Table 2.4.1	-90,504.6	-90,504.6	0.0	May include related party transactions.
[108]	Economic and Market Regulation - Shared costs	Table 2.4.1	0.0			
[109]	Employee costs - % allocated to pipeline	Table 2.4.1	0.00%			
[110]	Information technology and communication costs - % allocated to pipeline	Table 2.4.1	0.00%			

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[111]	Indirect operating Expenses - % allocated to pipeline	Table 2.4.1	0.00%			
[112]	Shared asset depreciation - % allocated to pipeline	Table 2.4.1	0.00%			
[113]	Rental and leasing costs - % allocated to pipeline	Table 2.4.1	0.00%			
[114]	Borrowing costs - % allocated to pipeline	Table 2.4.1	0.00%			
[115]	Loss from sale of shared fixed assets - % allocated to pipeline	Table 2.4.1	0.00%			
[116]	Impairment Losses (nature of the impairment loss) - % allocated to pipeline	Table 2.4.1	0.00%			
[117]	Other shared costs - % allocated to pipeline	Table 2.4.1	0.00%			
[118]	Finance - % allocated to pipeline	Table 2.4.1	100.00%			
[119]	Information and Communication Technology - % allocated to pipeline	Table 2.4.1	100.00%			
[120]	Information & Communcations Systems - % allocated to pipeline	Table 2.4.1				
[121]	Administration and Executive - % allocated to pipeline	Table 2.4.1	100.00%			
[122]	Business and Planning (External Relations) - % allocated to pipeline	Table 2.4.1	100.00%			
[123]	External Relations - % allocated to pipeline	Table 2.4.1				
[124]	Legal Counse/Company Secretary - % allocated to pipeline	Table 2.4.1	100.00%			
[125]	Legal & Corporate Affairs - % allocated to pipeline	Table 2.4.1				

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[126]	Contract Management - % allocated to pipeline	Table 2.4.1	100.00%			
[127]	Regulatory Strategy - % allocated to pipeline	Table 2.4.1	100.00%			
[128]	Economic and Market Regulation - % allocated to pipeline	Table 2.4.1				
[129]	3. Statement of pipeline assets					
[130]	Pipelines	Table 3.1	Header of [131] to [137].			TBG entry.
[131]	Pipelines - Initial construction cost	Table 3.1	86,552,883.0			Entry is inclusive of reporting period.
[132]	Pipelines - Additions	Table 3.1	3,434,725.8			Entry is inclusive of reporting period.
[133]	Pipelines - Capitalised maintenance	Table 3.1	0.0			Entry is inclusive of reporting period.
[134]	Total capitalised pipeline construction costs	Table 3.1	89,987,608.8			Entry is inclusive of reporting period.
[135]	Pipelines - Asset disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[136]	Pipelines - Less depreciation	Table 3.1	-9,142,638.9			Entry is inclusive of reporting period.
[137]	Closing pipeline carrying value	Table 3.1	80,844,969.9			Entry is inclusive of reporting period.
[138]	Compressors	Table 3.1	0.0			Entry is inclusive of reporting period.
[139]	Compressors - Initial purchase costs	Table 3.1	0.0			Entry is inclusive of reporting period.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[140]	Compressors - Additions and improvements capitalised	Table 3.1	0.0			Entry is inclusive of reporting period.
[141]	Compressors - Depreciation of compressors	Table 3.1	0.0			Entry is inclusive of reporting period.
[142]	Compressors - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[143]	Closing compressors carrying value	Table 3.1	0.0			Entry is inclusive of reporting period.
[144]	City gates, supply regulators and valve stations	Table 3.1	0.0			Entry is inclusive of reporting period.
[145]	City gates, supply regulators and valve stations - Initial purchase costs	Table 3.1	180,692.0			Entry is inclusive of reporting period.
[146]	City gates, supply regulators and valve stations - Improvements capitalised	Table 3.1	17,903.9			Entry is inclusive of reporting period.
[147]	City gates, supply regulators and valve stations - Depreciation of city gates, supply regulators and valve stations	Table 3.1	-31,027.1			Entry is inclusive of reporting period.
[148]	City gates, supply regulators and valve stations - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[149]	Closing city gates, supply regulators and valve stations carrying value	Table 3.1	167,568.8			Entry is inclusive of reporting period.
[150]	Metering	Table 3.1	0.0			Entry is inclusive of reporting period.
[151]	Metering - Initial purchase costs	Table 3.1	0.0			Entry is inclusive of reporting period.
[152]	Metering - Additions and improvements capitalised	Table 3.1	3,689.4			Entry is inclusive of reporting period.
[153]	Metering - Depreciation of metering	Table 3.1	-417.6			Entry is inclusive of reporting period.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[154]	Metering - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[155]	Closing Metering	Table 3.1	3,271.8			Entry is inclusive of reporting period.
[156]	Odourant plants	Table 3.1	0.0			Entry is inclusive of reporting period.
[157]	Odourant plants - Initial purchase costs	Table 3.1	0.0			Entry is inclusive of reporting period.
[158]	Odourant plants - Additions and improvements capitalised	Table 3.1	0.0			Entry is inclusive of reporting period.
[159]	Odourant plants - Depreciation of odourant plants	Table 3.1	0.0			Entry is inclusive of reporting period.
[160]	Odourant plants - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[161]	Closing odourant plants carrying value	Table 3.1	0.0			Entry is inclusive of reporting period.
[162]	SCADA (Communications)	Table 3.1	0.0			Entry is inclusive of reporting period.
[163]	SCADA (Communications) - Initial purchase costs	Table 3.1	0.0			Entry is inclusive of reporting period.
[164]	SCADA (Communications) - Additions and improvements capitalised	Table 3.1	220,062.9			Entry is inclusive of reporting period.
[165]	SCADA (Communications) - Depreciation of SCADA	Table 3.1	-33,458.4			Entry is inclusive of reporting period.
[166]	SCADA (Communications) - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[167]	Closing SCADA carrying value	Table 3.1	186,604.5			Entry is inclusive of reporting period.
[168]	Buildings	Table 3.1	0.0			Entry is inclusive of reporting period.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[169]	Buildings - Initial purchase costs	Table 3.1	76,657.2			Entry is inclusive of reporting period.
[170]	Buildings - Additions and improvements capitalised	Table 3.1	0.0			Entry is inclusive of reporting period.
[171]	Buildings - Depreciation of buildings	Table 3.1	-7,847.1			Entry is inclusive of reporting period.
[172]	Buildings - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[173]	Closing buildings carrying value	Table 3.1	68,810.1			Entry is inclusive of reporting period.
[174]	Land and easements	Table 3.1	0.0			Entry is inclusive of reporting period.
[175]	Land and easements - Initial purchase costs	Table 3.1	0.0			Entry is inclusive of reporting period.
[176]	Land and easements - Additions and improvements capitalised	Table 3.1	123,285.7			Entry is inclusive of reporting period.
[177]	Land and easements - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.
[178]	Closing land and easements carrying value	Table 3.1	123,285.7			Entry is inclusive of reporting period.
[179]	Other depreciable pipeline assets	Table 3.1	0.0			Entry is inclusive of reporting period.
[180]	Other depreciable pipeline assets - Intitial purchase/improvement cost	Table 3.1	328,530.8			Entry is inclusive of reporting period.
[181]	Other depreciable pipeline assets - Additions and improvements capitalised	Table 3.1	494,938.8			Entry is inclusive of reporting period.
[182]	Other depreciable pipeline assets - Depreciation/amortisation	Table 3.1	-445,843.7			Entry is inclusive of reporting period.
[183]	Other depreciable pipeline assets - Disposal (at cost)	Table 3.1	0.0			Entry is inclusive of reporting period.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[184]	Closing other depreciable pipeline assets carrying value	Table 3.1	377,625.9			Entry is inclusive of reporting period.
[185]	Other non-depreciable pipeline assets	Table 3.1	1,276,027.1			Entry is inclusive of reporting period.
[186]	Total pipeline assets	Table 3.1	83,048,163.6			Entry is inclusive of reporting period.
[187]	Shared supporting assets	Table 3.1	0.0			Entry is inclusive of reporting period.
[188]	Shared property, plant and equipment at cost	Table 3.1	4,462,320.8			Entry is inclusive of reporting period.
[189]	Shared property, plant and equipment - Additions and improvements capitalised	Table 3.1	0.0			Entry is inclusive of reporting period.
[190]	Shared property, plant and equipment - Shared property, plant and equipment depreciation	Table 3.1	-2,816,926.6			Entry is inclusive of reporting period.
[191]	Closing shared property, plant and equipment	Table 3.1	1,645,394.2			Entry is inclusive of reporting period.
[192]	Inventories	Table 3.1	0.0			Entry is inclusive of reporting period.
[193]	Deferred tax assets	Table 3.1	0.0			Entry is inclusive of reporting period.
[194]	Other assets	Table 3.1	0.0			Entry is inclusive of reporting period.
[195]	Total shared supporting assets allocated	Table 3.1	1,645,394.2			Entry is inclusive of reporting period.
[196]	Total assets	Table 3.1	84,693,557.9			Entry is inclusive of reporting period.

[197] 3.1 Pipeline asset useful life

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[198]	- Acqusition date [sic]	Table 3.1.1				TBG entry
[199]	Pipelines - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[200]	Compressors - Acqusition date	Table 3.1.1	0			
[201]	City Gates, supply regulators and valve stations - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[202]	Metering - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[203]	Odourant plants - Acqusition date	Table 3.1.1	0			
[204]	SCADA (Communications) - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[205]	Buildings - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[206]	Other depreciable pipeline assets - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			TBG entry.
[207]	Land and easements - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[208]	Shared supporting assets - Acqusition date	Table 3.1.1	22/4/2010 to 30/6/2018			
[209]	Motor vehicles - Acqusition date	Table 3.1.1				
[210]	ICT assets - Acqusition date	Table 3.1.1				
[211]	Roads - Acqusition date	Table 3.1.1				
[212]	- Useful life	Table 3.1.1				TBG entry.
[213]	Pipelines - Useful life	Table 3.1.1	80			
[214]	Compressors - Useful life	Table 3.1.1	35			
[215]	City Gates, supply regulators and valve stations - Useful life	Table 3.1.1	50			
[216]	Metering - Useful life	Table 3.1.1	50			
[217]	Odourant plants - Useful life	Table 3.1.1	80			
[218]	SCADA (Communications) - Useful life	Table 3.1.1	15			

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[219]	Buildings - Useful life	Table 3.1.1	80			
[220]	Other depreciable pipeline assets - Useful life	Table 3.1.1	5-80			
[221]	Land and easements - Useful life	Table 3.1.1	n/a			
[222]	Shared supporting assets - Useful life	Table 3.1.1	5			
[223]	Motor vehicles - Useful life	Table 3.1.1				
[224]	ICT assets - Useful life	Table 3.1.1				
[225]	Roads - Useful life	Table 3.1.1				
[226]	3.2 Pipeline asset impairment					
[227]	Assets impaired - no entries	Table 3.2.1	0			
[228]	Asset impairment reversals - no entries	Table 3.2.2	0			
[229]	3.3 Depreciation					
[230]	- Acquisition date	Table 3.3.1				TBG entry.
[231]	Pipelines - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[232]	Compressors - Acquisition date	Table 3.3.1	0			
[233]	City Gates, supply regulators and valve stations - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[234]	Metering - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[235]	Odourant plants - Acquisition date	Table 3.3.1	0			
[236]	SCADA (Communications) - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[237]	Buildings - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[238]	Land and easements - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[239]	Other depreciable pipeline assets - Acquisition date	Table 3.3.1	22/4/2010 to 30/6/2018			
[240]	Shared supporting assets - Acquisition date	Table 3.3.1				
[241]	Other non-depreciable pipeline assets - Acquisition date	Table 3.3.1				
[242]	- Useful life	Table 3.3.1				TBG entry.
[243]	Pipelines - Useful life	Table 3.3.1	80			
[244]	Compressors - Useful life	Table 3.3.1	35			
[245]	City Gates, supply regulators and valve stations - Useful life	Table 3.3.1	50			
[246]	Metering - Useful life	Table 3.3.1	50			
[247]	Odourant plants - Useful life	Table 3.3.1	80			
[248]	SCADA (Communications) - Useful life	Table 3.3.1	15			
[249]	Buildings - Useful life	Table 3.3.1	80			
[250]	Land and easements - Useful life	Table 3.3.1	n/a			
[251]	Other depreciable pipeline assets - Useful life	Table 3.3.1	5-80			
[252]	Shared supporting assets - Useful life	Table 3.3.1				
[253]	Other non-depreciable pipeline assets - Useful life	Table 3.3.1				
[254]	- Estimated residual value	Table 3.3.1				TBG entry.
[255]	Pipelines - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[256]	Compressors - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[257]	City Gates, supply regulators and valve stations - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[258]	Metering - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[259]	Odourant plants - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[260]	SCADA (Communications) - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[261]	Buildings - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[262]	Land and easements - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[263]	Other depreciable pipeline assets - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[264]	Shared supporting assets - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[265]	Other non-depreciable pipeline assets - Estimated residual value	Table 3.3.1	0.0			Sum of entries with same category.
[266]	- Construction or acquisition cost	Table 3.3.1				TBG entry.
[267]	Pipelines - Construction or acquisition cost	Table 3.3.1	86,552,883.0			Sum of entries with same category.
[268]	Compressors - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[269]	City Gates, supply regulators and valve stations - Construction or acquisition cost	Table 3.3.1	180,692.0			Sum of entries with same category.
[270]	Metering - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[271]	Odourant plants - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[272]	SCADA (Communications) - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[273]	Buildings - Construction or acquisition cost	Table 3.3.1	76,657.2			Sum of entries with same category.
[274]	Land and easements - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[275]	Other depreciable pipeline assets - Construction or acquisition cost	Table 3.3.1	328,530.8			Sum of entries with same category.
[276]	Shared supporting assets - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[277]	Other non-depreciable pipeline assets - Construction or acquisition cost	Table 3.3.1	0.0			Sum of entries with same category.
[278]	- Additions	Table 3.3.1				TBG entry.
[279]	Pipelines - Additions	Table 3.3.1	3,434,725.8			Sum of entries with same category.
[280]	Compressors - Additions	Table 3.3.1	0.0			Sum of entries with same category.
[281]	City Gates, supply regulators and valve stations - Additions	Table 3.3.1	17,903.9			Sum of entries with same category.
[282]	Metering - Additions	Table 3.3.1	3,689.4			Sum of entries with same category.
[283]	Odourant plants - Additions	Table 3.3.1	0.0			Sum of entries with same category.
[284]	SCADA (Communications) - Additions	Table 3.3.1	220,062.9			Sum of entries with same category.
[285]	Buildings - Additions	Table 3.3.1	0.0			Sum of entries with same category.
[286]	Land and easements - Additions	Table 3.3.1	123,285.7			Sum of entries with same category.
[287]	Other depreciable pipeline assets - Additions	Table 3.3.1	494,938.8			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[288]	Shared supporting assets - Additions	Table 3.3.1	0.0			Sum of entries with same category.
[289]	Other non-depreciable pipeline assets - Additions	Table 3.3.1	0.0			Sum of entries with same category.
[290]	- Capitalised maintenance	Table 3.3.1				TBG entry.
[291]	Pipelines - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[292]	Compressors - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[293]	City Gates, supply regulators and valve stations - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[294]	Metering - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[295]	Odourant plants - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[296]	SCADA (Communications) - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[297]	Buildings - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[298]	Land and easements - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[299]	Other depreciable pipeline assets - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[300]	Shared supporting assets - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[301]	Other non-depreciable pipeline assets - Capitalised maintenance	Table 3.3.1	0.0			Sum of entries with same category.
[302]	- Disposals	Table 3.3.1				TBG entry.
[303]	Pipelines - Disposals	Table 3.3.1	0.0			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[304]	Compressors - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[305]	City Gates, supply regulators and valve stations - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[306]	Metering - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[307]	Odourant plants - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[308]	SCADA (Communications) - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[309]	Buildings - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[310]	Land and easements - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[311]	Other depreciable pipeline assets - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[312]	Shared supporting assets - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[313]	Other non-depreciable pipeline assets - Disposals	Table 3.3.1	0.0			Sum of entries with same category.
[314]	- Cost base	Table 3.3.1				TBG entry.
[315]	Pipelines - Cost base	Table 3.3.1	89,987,608.8			Sum of entries with same category.
[316]	Compressors - Cost base	Table 3.3.1	0.0			Sum of entries with same category.
[317]	City Gates, supply regulators and valve stations - Cost base	Table 3.3.1	198,595.9			Sum of entries with same category.
[318]	Metering - Cost base	Table 3.3.1	3,689.4			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[319]	Odourant plants - Cost base	Table 3.3.1	0.0			Sum of entries with same category.
[320]	SCADA (Communications) - Cost base	Table 3.3.1	220,062.9			Sum of entries with same category.
[321]	Buildings - Cost base	Table 3.3.1	76,657.2			Sum of entries with same category.
[322]	Land and easements - Cost base	Table 3.3.1	123,285.7			Sum of entries with same category.
[323]	Other depreciable pipeline assets - Cost base	Table 3.3.1	823,469.6			Sum of entries with same category.
[324]	Shared supporting assets - Cost base	Table 3.3.1	0.0			Sum of entries with same category.
[325]	Other non-depreciable pipeline assets - Cost base	Table 3.3.1	0.0			Sum of entries with same category.
[326]	- Prior years' accumulated depreciation	Table 3.3.1				TBG entry.
[327]	Pipelines - Prior years' accumulated depreciation	Table 3.3.1	-8,584,839.0			Sum of entries with same category.
[328]	Compressors - Prior years' accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[329]	City Gates, supply regulators and valve stations - Prior years' accumulated depreciation	Table 3.3.1	-29,057.4			Sum of entries with same category.
[330]	Metering - Prior years' accumulated depreciation	Table 3.3.1	-381.0			Sum of entries with same category.
[331]	Odourant plants - Prior years' accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[332]	SCADA (Communications) - Prior years' accumulated depreciation	Table 3.3.1	-26,183.3			Sum of entries with same category.
[333]	Buildings - Prior years' accumulated depreciation	Table 3.3.1	-7,371.9			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[334]	Land and easements - Prior years' accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[335]	Other depreciable pipeline assets - Prior years' accumulated depreciation	Table 3.3.1	-433,874.0			Sum of entries with same category.
[336]	Shared supporting assets - Prior years' accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[337]	Other non-depreciable pipeline assets - Prior years' accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[338]	- Current year accumulated depreciation	Table 3.3.1				TBG entry.
[339]	Pipelines - Current year accumulated depreciation	Table 3.3.1	-557,799.9			Sum of entries with same category.
[340]	Compressors - Current year accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[341]	City Gates, supply regulators and valve stations - Current year accumulated depreciation	Table 3.3.1	-1,969.6			Sum of entries with same category.
[342]	Metering - Current year accumulated depreciation	Table 3.3.1	-36.6			Sum of entries with same category.
[343]	Odourant plants - Current year accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[344]	SCADA (Communications) - Current year accumulated depreciation	Table 3.3.1	-7,275.1			Sum of entries with same category.
[345]	Buildings - Current year accumulated depreciation	Table 3.3.1	-475.2			Sum of entries with same category.
[346]	Land and easements - Current year accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[347]	Other depreciable pipeline assets - Current year accumulated depreciation	Table 3.3.1	-11,969.7			Sum of entries with same category.

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[348]	Shared supporting assets - Current year accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[349]	Other non-depreciable pipeline assets - Current year accumulated depreciation	Table 3.3.1	0.0			Sum of entries with same category.
[350]	- Written down value	Table 3.3.1				TBG entry.
[351]	Pipelines - Written down value	Table 3.3.1	80,844,969.9			Sum of entries with same category.
[352]	Compressors - Written down value	Table 3.3.1	0.0			Sum of entries with same category.
[353]	City Gates, supply regulators and valve stations - Written down value	Table 3.3.1	167,568.8			Sum of entries with same category.
[354]	Metering - Written down value	Table 3.3.1	3,271.8			Sum of entries with same category.
[355]	Odourant plants - Written down value	Table 3.3.1	0.0			Sum of entries with same category.
[356]	SCADA (Communications) - Written down value	Table 3.3.1	186,604.5			Sum of entries with same category.
[357]	Buildings - Written down value	Table 3.3.1	68,810.1			Sum of entries with same category.
[358]	Land and easements - Written down value	Table 3.3.1	123,285.7			Sum of entries with same category.
[359]	Other depreciable pipeline assets - Written down value	Table 3.3.1	377,625.9			Sum of entries with same category.
[360]	Shared supporting assets - Written down value	Table 3.3.1	0.0			Sum of entries with same category.
[361]	Other non-depreciable pipeline assets - Written down value	Table 3.3.1	0.0			Sum of entries with same category.
[362]	Shared assets - Construction cost	Table 3.3.2	4,462,320.8			
[363]	Shared assets - Additions	Table 3.3.2	0.0			

	Item	Table	Pipeline information	Excluding related party transactions	Related party transactions	Notes
[364]	Shared assets - Capitalised maintenance	Table 3.3.2	0.0			
[365]	Shared assets - Disposals	Table 3.3.2	0.0			
[366]	Shared assets - Depreciation	Table 3.3.2	-2,816,926.6			
[367]	Shared assets - Written down value	Table 3.3.2	1,645,394.2			
[368]	3.4 Shared supporting assets					
[369]	Column E	Table 3.4.1	Total amount			TBG entry.
[370]	Information Technology - Total amount	Table 3.4.1	4,462,320.8			
[371]	Software - Total amount	Table 3.4.1				
[372]	IT Computers Desktop - Total amount	Table 3.4.1				
[373]	Bldg Make-Good Prov - Total amount	Table 3.4.1				
[374]	Column F	Table 3.4.1	% allocated to the pipeline			TBG entry.
[375]	Information Technology - % allocated to pipeline	Table 3.4.1	100.00%			
[376]	Software - % allocated to pipeline	Table 3.4.1				
[377]	IT Computers Desktop - % allocated to pipeline	Table 3.4.1				
[378]	Bldg Make-Good Prov - % allocated to pipeline	Table 3.4.1				

Notes:
"TBG entry" indicates that a line item was added by The Brattle Group to assist with using the information in later analyses in Excel and recording the sources of information."

Appendix C—Mapping Part 23 to Part 8 – 12

Mapping of Part 23 to Parts 8-12 reporting

	Component		Method	Method	Actual or forecast		Reporting period	
Item	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[1]	Total revenue	a) Current Maximum Allowed Revenue b) Revenue of rebateable services	Part 23 requires the disclosure of actual "Total revenue". For the most recent reporting period, revenue is reported as the sum of "Total direct revenue" and "Total indirect revenue allocated". Direct revenue is "revenue directly earned by the pipeline" and indirect revenue is "[a]ny other revenue that does not directly relate to a specific pipeline" (AER Guideline, p. 15). Direct revenue is reported for each service type within a list of specified services (such as firm forward haul transportation, park and park and loan, etc.). Service providers are required to report the methodology they use to allocate indirect revenue (see allocation principles). For the recovered cost of capital method, service providers are required to report the total revenue in each year following the construction of the asset.	Service providers are required to estimate "Maximum Allowed Revenue" using the building block approach (National Gas Rules, Version 47, Rule 76). Maximum Allowed Revenue is a prospective figure calculated for each year of the subsequent regulatory period, estimated based on forecasted cost components (return on and capital, operating expenditures, and taxes). Historical actual revenues are not reported under Parts 8-12. In the case of the Roma to Brisbane Pipeline's 2017-2022 access arrangement, APTPPL is required to rebate 70% of revenue it earns from rebateable services to shippers who are contracting reference services (RBP Final Decision, p. 17). Therefore, APTPPL is required to report the revenue it has earned during the prior financial year in respect of park and loan services, in-pipe trading services and capacity trading services. These revenues are reported through the pipeline's notification of annual tariff variation.	Actual	Forecast (and limited historical actuals)	Detailed revenue breakdown is reported for the most recent reporting period (6 months prior to previous financial year). Yearly historical revenue is reported for every year since construction.	Next (5-year) regulatory period. Previous financial year for rebateable service revenue.
[2]	Operating expenses	Operating expenses	For the current reporting period, service providers are required to report "Total costs", which is calculated as the sum of "Total direct costs" and "Total shared costs allocated". "Total direct costs" includes depreciation and other components such as "[r]epairs and maintenance" and "[w]ages". "Total shared costs allocated" includes components such as "[e]mployee costs", "[i]nformation technology and communication costs" and "[i]ndirect operating [e]xpenses". Service providers are required to disclose the allocators used to allocate shared costs to individual non-scheme pipelines (AER Guideline, pp. 14-16). Part 23 also requires non-scheme pipelines to report a component called "Operating Expenses". This component is reported on an annual basis for each year since the construction of the pipeline in the recovered capital method.	Historical and forecast total operating expenditure ("Total Opex') are reported in the forecast operating expenditure model. "Total Opex" is reported as the sum of several components, including "Labour", "Contractors", "Other operating costs", "Insurance, Licences and fees", "Overheads/corporate costs", "General", "Management services fees" and "Treasury/financing costs".	Actual	Forecast and actual	Total cost is reported for the most recent reporting period. Opex is reported for every year since construction.	Reports the historical values for the ending regulatory period and forecasts for the next regulatory period.

	Component		Method	Method	Actual or forecast		Reporting period	
Item	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[3]	Total assets	Closing Regulatory Asset Base - As Incurred (RFM); Closing RAB (PTRM)	Total assets are reported under two methods: depreciated book value and recovered capital method (RCM). a) Under the depreciated book value method, total asset value at the end of the current reporting period is calculated as the original construction cost (or acquisition cost) of the asset plus additions, disposal costs and capitalised maintenance, less depreciation. Closing carrying values for various asset classes (eg, pipeline, compressors, SCADA) are also reported individually. b) Under the RCM, the value of the pipeline assets at year t is estimated as the original construction cost of the pipeline, plus accumulated capex (from the time that the pipeline was constructed), subtracting disposals and the return of capital that have occurred since the pipeline was constructed. Return of capital is not calculated using a conventional depreciation method. It is calculated as the residual revenue after accounting for operating expenditure, return on capital and taxes. Under both methods, total assets and its components are broken into assets that support the services provided by only the reporting pipeline (pipeline assets or direct assets) and assets that support the services provided by this and other pipelines (shared assets or shared supporting assets).	The asset base is set when the pipeline first becomes regulated (see original construction cost below). From that point on, the asset base is rolled forward in each regulatory period. The roll forward method adjusts the asset base for capex, depreciation and disposals, and reports the updated asset base in real and nominal terms. The roll forward model (RFM) reports the Regulatory Asset Base (RAB) for the current regulatory period (which is ending) while the post-tax revenue model (PTRM) reports the forecast RAB for the next regulatory period. The RFM uses actual capex, while the PTRM uses forecast capex for the next regulatory period.	Actual	Forecast and actual	The depreciated book value is the closing value for the current reporting period. A closing asset value for each year since construction can be estimated under the RCM.	Actual values are provided for the ending regulatory period (excluding the years for which the data are incomplete, as will be the case if the access arrangement process is settled before the end of this regulatory period). Forecast values are provided for the subsequent regulatory period.
[4]	Initial construction cost/Initial purchase cost	Opening asset value (partially as incurred)	Under the depreciated book value method, the AER Guideline requires the service provider to report either (i) the initial construction cost of the asset or, if the asset was acquired by the service provider, (ii) the acquisition cost of the asset. The service provider is not permitted to use a revaluation of the asset in place of construction or acquisition cost. Under the RCM, service providers have to report the construction costs of assets incurred before commissioning of the pipeline. Acquisition costs can only be used for asset types not typically constructed by the service providers (such as motor vehicles). The AER Guideline states that "if a service provider does not build pipeline assets but acquires them, they are not able to use the acquisition cost of the asset but must use historical construction cost". If historical construction cost is not available (eg, by request from the asset's original owner) the service provider is permitted to estimate construction costs.	The method used for the initial valuation of pipeline assets at the time of becoming a covered pipeline depends on when the pipeline was commissioned. This is governed by Rule 77 of the National Gas Rules. If a pipeline was already commissioned when the NGR came into effect, then the relevant provisions of the Gas Code apply to initial valuation. If a pipeline was commissioned after the NGR came into effect, the initial asset base is determined as historical construction costs plus capex, less depreciation and disposals up to the point of coverage. For pipelines that were commissioned before the NGR came into effect, the initial asset value is typically determined through a regulatory process.	Actual	Actual	N/A	N/A

Item	Component		Method	Method	Actual or forecast		Reporting period	
	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[5]	Additions and capitalised maintenance	Capital expenditure (Capex Model)	Cumulative historical capex since construction or acquisition of the pipeline is reported under the depreciated book value method. In addition, historical capex is reported for each year since the commissioning of the asset under the recovered capital method (note here that the AER Guideline says since commissioning, but the AER Explanatory Statement says since the asset was constructed). It appears that the total value of capex is not necessarily the same across the two methods. Capitalisation of operating expenditure is governed by the Australian Accounting Standards, which allows for capitalization of the cost of major inspections (AASB, "AASB 116 Property, Plant and Equipment").	Service providers report both historical capex for the ending regulatory period and forecast capex for the subsequent regulator period. Historical capex is used in the RFM while forecast capex is used in the PTRM. In some cases, service providers will capitalise expenditure that might be considered as opex where it contributes to the value of the asset: "capitalised overheads". See notes for the capitalisation policy.*	Actual	Actual and forecast	Accumulated capex from construction to the end of the current reporting period; actual capex for each year since the construction of the pipeline in the recovered capital method.	Actual values are provided for each year of the ending regulatory period. Forecast values are provided for each year of the next regulatory period.
[6]	Disposal costs	Disposals (capex model)	The reporting requirements for disposals are similar to the reporting requirements for capital expenditure under Part 23. Disposals must be derecognised from the carrying value of an asset. Disposals are reported at cost where applicable. Under the Australian Accounting Standards, derecognition of an asset must occur at the carrying amount of the asset (AASB, "AASB 116 Property, Plant and Equipment", paragraph 70).	The RFM reports historical disposals for the ending regulatory period and the PTRM reports forecast disposals for the next regulatory period.	Actual	Actual and forecast	Similar to [5].	Similar to [5].

Item	Component		Method	Method	Actual or forecast		Reporting period	
	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[7]	Depreciation	Forecast regulatory depreciation	Service providers report cumulative nominal depreciation from construction or acquisition of the pipeline. Depreciation is calculated according to methods that conform to Australian Accounting Standards (AER Explanatory Statement, p. 17). AAS do not allow land or easements to be depreciated. AAS allow straight-line depreciation, diminishing balance depreciation, and units of production depreciation (AASB, "AASB 116 Property, Plant and Equipment", paragraph 62).	Nominal forecast regulatory depreciation is given for each year of the previous reporting period. Depreciation is calculated on assets as commissioned such that fully regulated pipeline owners can only receive a return of capital on assets that are presently in operation. Rule 89 of the NGR gives criteria for the depreciation method used by covered pipelines. These criteria cover essential elements of depreciation (eg, depreciation occurs over the economic life of the asset, an asset may only be depreciated once), but are not specific about calculation method (see Part 9 of the NGR). Rule 89 of the NGR indicates that covered pipelines must choose an accounting method for depreciation that is allowed by the AER. The AER has been using the straight-line method. The PTRM forecasts asset depreciation to calculate the return of capital building block in the reference tariff determination. The PTRM calculates regulatory depreciation as nominal straight-line depreciation on the opening RAB in a given year minus the inflation on the opening RAB expected to occur in that year. This adjustment for inflation on the opening RAB is used to correct for the double counting of inflation that occurs in the return on capital building block. Double counting occurs in return on capital because the nominal opening RAB is multiplied by a nominal WACC. The resulting return on capital value is equal to real return on capital, indexed to account for present year inflation, plus the inflation on the nominal opening RAB. The negative adjustment in the depreciation building block precisely corrects for this additional term in the return on capital calculation.	Actual	Forecast	Accumulated since construction or acquisition.	Next regulatory period.

	Component		Method	Method	Actual or forecast		Reporting period	
Item	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[8]	Asset useful life	Standard Life (Year) / Average Remaining Life (Year)	Service providers are required to disclose the asset life for the different asset classes set out by the AER (such as pipelines, compressors, city gates, metering, SCADA, and shared supporting assets). The AER sets out a "common range" of asset lives (AER Guideline, p. 9). Service providers that use different asset lives to those set out by the AER need to provide an explanation in the basis of preparation.	Service providers report two remaining life figures (expressed in years) in the RFM: the average remaining life of each asset class for each year of the past regulatory period and forecasted for future years, and the standard life. Average remaining life is a weighted average rolled forward based on capex, disposals and depreciation (see 2.1 of the AER's Amendment to the ETNSP RFM Handbook). The Roma to Brisbane RFM from November 2017 shows that Weighted Average Remaining Life (WARL) is calculated as the sum of the standard useful life of capex from each past year, weighted by the share of depreciated RAB for that asset that the capex from that year comprises. Average remaining life is used to forecast depreciation on the opening asset base at the start of the regulatory period. Standard life is the estimated useful economic life of an asset at the point of being built, ignoring future additions (ie, its whole life as a standalone asset). Covered pipelines do not seem to be required to justify this standard life, but do face regulatory oversight on their proposals. Examples of asset classes for which these two figures are provided include pipelines, compressors, regulators and meters, communications, and group IT. Standard life is used to forecast depreciation on forecast capex over the regulatory period.	Forecast	Forecast	Current reporting period	WARL is estimated for each year of the previous reporting period, and, in the case of Roma to Brisbane Pipeline's PTRM for 2017-22, the following fourteen financial years.
[9]	Net tax liability	Net tax allowance	Service providers are required to estimate net tax liabilities for the recoverd capital method and to disclose the method used to calculate these values. Most service providers attempt to estimate what a pipeline's net tax liabilities would be were it to operate as a separate entity. Service providers "have the option to account for tax using either a pre-tax commercial rate of return, or the post-tax approach with net tax liabilities modelled explicitly" (AER Explanatory Statement, p. 25).	Service providers are required to estimate the cost of coporate income tax for each regulatory year of an access arrangement period, net of allowed imputation credits for that regulatory year (see division 5A of Part 9 of the NGR). Up until this year (2019), tax has been estimated using the tax building block which forecast tax costs for a benchmark entity using a standard tax calculation that has regard to regulatory estimates of taxable revenue, tax expenses (depreciation, interest, opex) and the statutory corporate income tax rate (30 per cent). The AER recently introduced changes to the PTRM in order to (i) recognise the ability to immediately expense some capex and (ii) use the diminishing value (DV) method to estimate tax depreciation for new assets. The AER states that the DV reflects the practice used by other non-National Tax Equivalent Regime entites and allows for faster and earlier tax depreciation (ie, less tax over the life of the asset in NPV term).	Estimated historical	Forecast	Each year since construction or commissioning of the pipeline (the AER Guideline variously refers to commissioning and construction on pages 18-20).	Next (5-year) regulatory period.

	Component		Method	Method	Actual or forecast		Reporting period	
Item	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[10]	Weighted average price	N/A	Non-scheme pipelines are required to report the weighted average price (WAP) of services offered on their pipeline in the previous reporting period. Weighted average price is equal to the revenue from a service during the reporting period divided by the quantity of that service provided. Service providers are required to report the WAP for individual services (eg, "[t]ransportation services", "[s]tand-alone firm compression services" or "[p]ark and park and loan". There are situations where estimates may be required for WAP such as when a shipper uses two or more pipelines under one agreement (or invoice) or when agreeements (invoices) do not separate revenue under a pipeline or service type (AER Explanatory Statement, p. 28). Service providers can obtain exemptions from reporting the WAP if either the service was provided, directly or indirectly to no more than two users of the non-scheme pipeline and the service provider gives notice to the AER at least 20 business days before the date required for publication certifying this (AER Explanatory Statement, p. 28).	N/A	Actual	N/A	The current reporting period	N/A
[11]	Volume/capacity		Service providers are required to disclose revenue by service under WAP reporting (Table 5.1 of the AER Template), categorising this revenue according to the charging method (postage stamp, zonal, or distance-based charging) as well as the basis of the charge, which can be the TJ of reserved maximum daily quantity (capacity-based charging) or the TJ of throughput (volumetric charging). Service providers report the two values needed to calculate the weighted average price of a service for a given charging method and basis: the revenue earned and the quantity sold. Depending on the services sold by the pipeline in the reporting period and the charging method used, a service provider may report contracted capacity (in Maximum Daily Quantity times days) or the throughput volume for a service. A particular service on a pipeline, or all pipeline services in some cases, may be exempt from WAP reporting if fewer than three shippers purchased the service in the reporting period (ie, one or two).	The Roma to Brisbane Pipeline access arrangement for 2017 to 2022 provides forecasts of annual throughput in each year of the access arrangement for the reference service. Under Rule 97(2) of Part 9 of the NGR, the formula that determines variation of a reference tariff in an access arrangement may provide for a revenue cap or a price cap. The Roma to Brisbane Pipeline access arrangement for 2017 to 2022 uses a price cap tariff variation mechanism (AER, "Final Decision Roma to Brisbane Gas Pipeline Access Arrangement 2017-22", p. 20).	Actual	Forecast	The current reporting period.	Next (5-year) regulatory period.

	Component		Method	Method	Actual or forecast		Reporting period	
Item	Part 23	Parts 8-12 (closest to equivalent)	Part 23	Parts 8-12	Part 23	Parts 8-12	Part 23	Parts 8-12
[12]	Return on assets	Return on Capital	Under part 23, a return on capital component is required in the valuation of pipeline assets in the recovered capital method. Service providers therefore have to estimate a commercial rate of return. Service providers are required to document the method, principles, assumptions and inputs that have been used in their basis of preparation and demonstrate that the estimate of the rate of return has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances. The only requirement from the AER Guideline is that the rate of return be "commensurate with the prevailing conditions in the market for funds and reflect the risks the service provider faces in providing pipeline services" (AER Guideline, p. 20). Note that the rate of return itself does not have to be reported. In addition, a "Return on assets" is calculated as actual EBIT divided by total assets. EBIT is calculated as "Total revenue" minus "Total costs", and "Total assets" is calculated as "Total pipeline assets" plus "Total shared supporting assets allocated".	Under Parts 8-12, the AER determines the rate of return on capital, which is used in the PTRM to calculate the return on capital, which is one of the components of the Maximum Allowed Revenue for the reference service. The AER prescribes the method of calculating the allowed rate of return, the rate of return on equity, and the rate of return on debt (AER (2018), Rate of Return Instrument). The AER uses certain assumptions in its calculations which are not estimated on a pipeline-by-pipeline basis but are standard across access arrangements (eg, gearing equal to 60%). The AER Rate of Return Instrument calculates the rate of return on equity using the Sharpe-Lintner Capital Asset Pricing Model (ie, return on equity equals an estimated risk-free rate of return plus the market risk premium multiplied by the allowed equity beta, which is assumed to be 0.6). The rate of return on debt is calculated using a "trailing average portfolio calculation" whereby return on debt equals the average of the previous ten years' estimated rates of return on debt (with transitional arrangements).	Historical	Forecast	Actual return on assets is reported for the current reporting period, and the estimated (reasonable) return on capital is reported for each year since the construction of the pipeline.	Next (5-year) regulatory period.

Sources and notes:

AASB (2015), AASB 116 Property, Plant and Equipment; AER (2013), Expenditure Forecast Assessment Guideline Explanatory Statement; AER (2013), Rate of Return Guidelines Explanatory Statement; AER (2015), Amendment to the ETNSP RFM Handbook; AER (2016), Australian Gas Networks Access Arrangement, Final Decision; AER (2016), Proposal Roma to Brisbane Gas Pipeline Access Arrangement 2017-22; AER (2017), Final Decision Roma to Brisbane Gas Pipeline Access Arrangement 2017-22; AER (2018), Rate of Return Instrument; National Gas Rules, Version 44, Part 9.

*Capitalisation of overheads under Parts 8-12: The capitalisation of overheads is governed by the AER's policy on "Property, plant and equipment". This policy states that overheads "attributable to bringing the asset to its working condition" may be included in construction costs (AER "Property, plant and equipment", p. 4), and that capitalisation of overheads "must cease once the project is transferred from work in progress to in-service" (AER "Property, plant and equipment", p. 5). Service providers "have to document their processes and methods of estimating the allocation of historical data" both in terms of cost allocation between services and cost allocation between opex and capex (see the explanatory statement on the AER Expenditure Forecast Assessment Guideline, p. 207). If a service provider changes its policy on capitalisation, the AER requires the service provider to identify how any changes affect data upon which the AER relies (explanatory statement on the AER Expenditure Forecast Assessment Guideline, p. 208). Service providers submit capitalisation policies to the AER that must conform with AASB standards, including 116 - Property plant and equipment. The AER's (2013) Capital Expenditure Incentive Guide indicates that the AER does not pay attention to changes in a service provider's capitalisation policy where that service provider's incentives for opex and capex efficiencies are balanced (See Capex Incentive Guide, 4.4.a). For example, a service provider's incentives will be balanced where it is subject to a capital expenditure sharing scheme (CESS) and an efficiency benefits sharing scheme (EBSS) with the same benefits rate. The AER conducts ex-post reviews of service providers' capex schedules for the first three years of the current regulatory period and the final two years of the previous regulatory period in order to correctly apply the CESS. The AER determines at this point whether to exclude capex from the RAB.

Appendix D—Part 8 – 12 Input lists

Model components RBP access arrangement, November 2017

Item	Model	Tab within model	Component	Notes
[1]	RFM	RFM Input	Opening Regulatory Asset Base for 2011-12 and Opening Tax Asset Base for 2012-13 ($m Nominal)	
[2]	RFM	RFM Input	- Asset Class Name	
[3]	RFM	RFM Input	- Opening Asset Value (Partially As Incurred)	
[4]	RFM	RFM Input	- Opening Asset Value (As Commissioned)	
[5]	RFM	RFM Input	- Average Remaining Life (Year)	
[6]	RFM	RFM Input	- Standard Life (Year)	
[7]	RFM	RFM Input	- Forecast Net Capex (As Incurred)	
[8]	RFM	RFM Input	- Forecast Net Capex (As Commissioned)	
[9]	RFM	RFM Input	- Forecast Regulatory Depreciation (Partially As Incurred)	
[10]	RFM	RFM Input	- Forecast Regulatory Depreciation (As Commissioned)	
[11]	RFM	RFM Input	- Difference in Final Year Capex (As Incurred)	
[12]	RFM	RFM Input	- Difference in Final Year Capex (As Commissioned)	
[13]	RFM	RFM Input	- Return on Difference in Final Year Capex (As Incurred)	
[14]	RFM	RFM Input	- Return on Difference in Final Year Capex (As Commissioned)	
[15]	RFM	RFM Input	- Other Final Year Adjustments (As Incurred)	
[16]	RFM	RFM Input	- Other Final Year Adjustments (As Commissioned)	
[17]	RFM	RFM Input	- Opening Tax Asset Value	
[18]	RFM	RFM Input	- Average Tax Remaining Life (Year)	
[19]	RFM	RFM Input	- Tax Standard Life (Year)	
[20]	RFM	RFM Input	- Base Regulatory Year	
[21]	RFM	RFM Input	- Length of Regulatory Control Period (Year)	
[22]	RFM	RFM Input	- Actual Capital Expenditure – As Incurred ($m Nominal)	For each Asset Class (of 12 for RBP)
[23]	RFM	RFM Input	- Actual Asset Disposal – As Incurred ($m Nominal)	For each Asset Class (of 12 for RBP)
[24]	RFM	RFM Input	Actual Net Capital Expenditure – As Incurred ($m Real 2011-12)	

Item	Model	Tab within model	Component	Notes
[25]	RFM	RFM Input	Actual Capital Expenditure – As Commissioned ($m Nominal)	
[26]	RFM	RFM Input	Actual Asset Disposal – As De-commissioned ($m Nominal)	
[27]	RFM	RFM Input	- Actual Net Capital Expenditure – As Commissioned ($m Real 2011-12)	For each Asset Class (of 12 for RBP)
[28]	RFM	RFM Input	Actual CPI Inflation Rate	
[29]	RFM	RFM Input	Actual CPI (one year lagged)	
[30]	RFM	RFM Input	Forecast Inflation Rate	
[31]	RFM	RFM Input	Forecast Inflation Cumulative Index	
[32]	RFM	RFM Input	Nominal Vanilla WACC	
[33]	RFM	RFM Input	Real Vanilla WACC	
[34]	RFM	RFM Input	Nominal vanilla WACC (fixed real time varying)	
[35]	RFM	RFM Input	Real Straight-line Depreciation Option	
[36]	RFM	RFM Input	- Forecast Real SL Depreciation	
[37]	RFM	RFM Input	- Actual Real SL Depreciation	
[38]	RFM	RFM Input	Forecast Straight-line Depreciation ($m Real 2011-12)	
[39]	RFM	RFM Input	Forecast Final Year (2016-17) Asset Adjustments ($m Nominal)	
[40]	RFM	RFM Input	RAB (As Incurred)	
[41]	RFM	RFM Input	RAB (As Commissioned)	
[42]	RFM	RFM Input	TAB	
[43]	RFM	RFM Input	Remaining Asset Life of Adjustments to RAB (years)	
[44]	RFM	RFM Input	Remaining Tax Asset Life of Adjustments to TAB (years)	
[45]	RFM	Adjustment for previous period	Actual CPI Inflation Rate	
[46]	RFM	Adjustment for previous period	Actual CPI (one year lagged)	
[47]	RFM	Adjustment for previous period	Nominal Vanilla WACC (fixed real time varying)	
[48]	RFM	Adjustment for previous period	Real Vanilla WACC	
[49]	RFM	Adjustment for previous period	Nominal Adjustments for Difference Between Forecast and Actual Net Capex - As Incurred	
[50]	RFM	Adjustment for previous period	- Nominal Forecast Net Capex (previous regulatory control period)	
[51]	RFM	Adjustment for previous period	- Nominal Actual Net Capex	

Item	Model	Tab within model	Component	Notes
[52]	RFM	Adjustment for previous period	- Nominal Difference Between Actual and Forecast Net Capex	
[53]	RFM	Adjustment for previous period	- Compounded Nominal Return on Difference - Net Capex	
[54]	RFM	Adjustment for previous period	- Total Return at End of Regulatory Period	
[55]	RFM	Adjustment for previous period	Nominal Adjustments for Difference Between Forecast and Actual Net Capex - As Commissioned	
[56]	RFM	Adjustment for previous period	- Nominal Forecast Net Capex (previous regulatory period)	
[57]	RFM	Adjustment for previous period	- Nominal Actual Net Capex	
[58]	RFM	Adjustment for previous period	- Nominal Difference Between Actual and Forecast Net Capex (indexed)	
[59]	RFM	Adjustment for previous period	- Compounded Real Return on Difference - Net Capex (as incurred)	
[60]	RFM	Adjustment for previous period	- Total Return at End of Regulatory Period (indexed)	
[61]	RFM	RAB roll forward	Actual CPI Inflation Rate	
[62]	RFM	RAB roll forward	Actual CPI (one year lagged)	
[63]	RFM	RAB roll forward	Asset Values ($m Real 2011-12)	
[64]	RFM	RAB roll forward	- Real Actual Net Capex - As Incurred	
[65]	RFM	RAB roll forward	- Real Actual Net Capex - As Commissioned	
[66]	RFM	RAB roll forward	- Real Forecast Straight-line Depreciation	
[67]	RFM	RAB roll forward	- Equity raising costs	
[68]	RFM	RAB roll forward	Asset Values – Partially As Incurred ($m Nominal)	
[69]	RFM	RAB roll forward	- Nominal Opening Regulatory Asset Base	
[70]	RFM	RAB roll forward	- Nominal Actual Net Capex	
[71]	RFM	RAB roll forward	- Nominal Forecast Regulatory Depreciation	
[72]	RFM	RAB roll forward	- Nominal Difference in Final Year Capex	
[73]	RFM	RAB roll forward	- Nominal Return on Difference in Final Year Capex	
[74]	RFM	RAB roll forward	- Nominal Other Final Year Adjustments	
[75]	RFM	RAB roll forward	- Nominal Forecast Straight-line Depreciation	
[76]	RFM	RAB roll forward	- Nominal Actual Inflation on Opening RAB	

Item	Model	Tab within model	Component	Notes
[77]	RFM	RAB roll forward	Asset Values – As Commissioned ($m Nominal)	
[78]	RFM	RAB roll forward	- Nominal Opening Regulatory Asset Base	
[79]	RFM	RAB roll forward	- Nominal Actual Net Capex	
[80]	RFM	RAB roll forward	- Nominal Forecast Regulatory Depreciation	
[81]	RFM	RAB roll forward	- Nominal Difference in Final Year Capex	
[82]	RFM	RAB roll forward	- Nominal Return on Difference in Final Year Capex	
[83]	RFM	RAB roll forward	- Nominal Other Final Year Adjustments	
[84]	RFM	RAB roll forward	- Nominal Forecast Straight-line Depreciation	
[85]	RFM	RAB roll forward	- Nominal Actual Inflation on Opening RAB	
[86]	RFM	Total RAB roll forward	Asset Values – Partially As Incurred ($m Nominal)	
[87]	RFM	Total RAB roll forward	- Nominal Opening Regulatory Asset Base	
[88]	RFM	Total RAB roll forward	- Nominal Actual Net Capex	
[89]	RFM	Total RAB roll forward	- Nominal Forecast Regulatory Depreciation	
[90]	RFM	Total RAB roll forward	- Nominal Difference in Final Year Capex	
[91]	RFM	Total RAB roll forward	- Nominal Return on Difference in Final Year Capex	
[92]	RFM	Total RAB roll forward	- Nominal Other Final Year Adjustments	
[93]	RFM	Total RAB roll forward	Interim Closing Regulatory Asset Base – Partially As Incurred	
[94]	RFM	Total RAB roll forward	- Interim Closing Regulatory Asset Base	
[95]	RFM	Total RAB roll forward	- Difference Between Actual and Forecast Net Capex	
[96]	RFM	Total RAB roll forward	- Return on Difference - Net Capex	
[97]	RFM	Total RAB roll forward	- Final Year Asset Adjustments	
[98]	RFM	Total RAB roll forward	Closing Regulatory Asset Base – Partially As Incurred	
[99]	RFM	Total RAB roll forward	Asset Values – As Commissioned ($m Nominal)	

Item	Model	Tab within model	Component	Notes
[100]	RFM	Total RAB roll forward	- Nominal Opening Regulatory Asset Base	
[101]	RFM	Total RAB roll forward	- Nominal Actual Net Capex	
[102]	RFM	Total RAB roll forward	- Nominal Forecast Regulatory Depreciation	
[103]	RFM	Total RAB roll forward	- Nominal Difference in Final Year Capex	
[104]	RFM	Total RAB roll forward	- Nominal Return on Difference in Final Year Capex	
[105]	RFM	Total RAB roll forward	- Nominal Other Final Year Adjustments	
[106]	RFM	Total RAB roll forward	Interim Closing Regulatory Asset Base – As Commissioned	
[107]	RFM	Total RAB roll forward	- Interim Closing Regulatory Asset Base	
[108]	RFM	Total RAB roll forward	- Difference Between Actual and Forecast Net Capex	
[109]	RFM	Total RAB roll forward	- Return on Difference - Net Capex	
[110]	RFM	Total RAB roll forward	- Final Year Asset Adjustments	
[111]	RFM	Total RAB roll forward	Closing Regulatory Asset Base – As Commissioned	
[112]	RFM	TAB roll forward	Tax Values ($m Nominal)	
[113]	RFM	TAB roll forward	- Opening Tax Asset Values	
[114]	RFM	TAB roll forward	- Actual Net Capex	
[115]	RFM	TAB roll forward	- Actual Tax Depreciation	
[116]	RFM	RAB remaining lives	Weighted Average Remaining Asset Life - based on year-by-year tracked capex	
[117]	RFM	RAB remaining lives	- First regulatory year	
[118]	RFM	RAB remaining lives	- Actual CPI Inflation Rate	
[119]	RFM	RAB remaining lives	- Actual CPI (one year lagged)	
[120]	RFM	RAB remaining lives	- Nominal Vanilla WACC (fixed real time varying)	
[121]	RFM	RAB remaining lives	- Value of net addition ($nominal)	For each Asset Class (of 12 for RBP)
[122]	RFM	RAB remaining lives	- Asset life	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[123]	RFM	RAB remaining lives	- Value of RAB adjustment ($nominal)	For each Asset Class (of 12 for RBP)
[124]	RFM	RAB remaining lives	- Remaining life of RAB adjustment	For each Asset Class (of 12 for RBP)
[125]	RFM	RAB remaining lives	- Depreciated RAB adjustments	For each Asset Class (of 12 for RBP)
[126]	RFM	RAB remaining lives	- Depreciated starting RAB	For each Asset Class (of 12 for RBP)
[127]	RFM	RAB remaining lives	- Depreciated Net Capex 2012-13	For each Asset Class (of 12 for RBP)
[128]	RFM	RAB remaining lives	- Depreciated Net Capex 2013-14	For each Asset Class (of 12 for RBP)
[129]	RFM	RAB remaining lives	- Depreciated Net Capex 2014-15	For each Asset Class (of 12 for RBP)
[130]	RFM	RAB remaining lives	- Depreciated Net Capex 2015-16	For each Asset Class (of 12 for RBP)
[131]	RFM	RAB remaining lives	- Depreciated Net Capex 2016-17	For each Asset Class (of 12 for RBP)
[132]	RFM	RAB remaining lives	- Depreciated Net Capex 2017-18	For each Asset Class (of 12 for RBP)
[133]	RFM	RAB remaining lives	- Depreciated Net Capex 2018-19	For each Asset Class (of 12 for RBP)
[134]	RFM	RAB remaining lives	- Depreciated Net Capex 2019-20	For each Asset Class (of 12 for RBP)
[135]	RFM	RAB remaining lives	- Depreciated Net Capex 2020-21	For each Asset Class (of 12 for RBP)
[136]	RFM	RAB remaining lives	- Depreciated Net Capex 2021-22	For each Asset Class (of 12 for RBP)
[137]	RFM	RAB remaining lives	- Depreciated Net Capex 2022-23	For each Asset Class (of 12 for RBP)
[138]	RFM	RAB remaining lives	- Depreciated Net Capex 2023-24	For each Asset Class (of 12 for RBP)
[139]	RFM	RAB remaining lives	- Depreciated Net Capex 2024-25	For each Asset Class (of 12 for RBP)
[140]	RFM	RAB remaining lives	- Depreciated Net Capex 2025-26	For each Asset Class (of 12 for RBP)
[141]	RFM	RAB remaining lives	- Depreciated Net Capex 2026-27	For each Asset Class (of 12 for RBP)
[142]	RFM	RAB remaining lives	- Depreciated Net Capex 2027-28	For each Asset Class (of 12 for RBP)
[143]	RFM	RAB remaining lives	- Depreciated Net Capex 2028-29	For each Asset Class (of 12 for RBP)
[144]	RFM	RAB remaining lives	- Depreciated Net Capex 2029-30	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[145]	RFM	RAB remaining lives	- Depreciated Net Capex 2030-31	For each Asset Class (of 12 for RBP)
[146]	RFM	RAB remaining lives	- Depreciated Net Capex 2031-32	For each Asset Class (of 12 for RBP)
[147]	RFM	RAB remaining lives	- RL RAB adjustments	For each Asset Class (of 12 for RBP)
[148]	RFM	RAB remaining lives	- RL Start RAB	For each Asset Class (of 12 for RBP)
[149]	RFM	RAB remaining lives	- RL Capex 2012-13	For each Asset Class (of 12 for RBP)
[150]	RFM	RAB remaining lives	- RL Capex 2013-14	For each Asset Class (of 12 for RBP)
[151]	RFM	RAB remaining lives	- RL Capex 2014-15	For each Asset Class (of 12 for RBP)
[152]	RFM	RAB remaining lives	- RL Capex 2015-16	For each Asset Class (of 12 for RBP)
[153]	RFM	RAB remaining lives	- RL Capex 2016-17	For each Asset Class (of 12 for RBP)
[154]	RFM	RAB remaining lives	- RL Capex 2017-18	For each Asset Class (of 12 for RBP)
[155]	RFM	RAB remaining lives	- RL Capex 2018-19	For each Asset Class (of 12 for RBP)
[156]	RFM	RAB remaining lives	- RL Capex 2019-20	For each Asset Class (of 12 for RBP)
[157]	RFM	RAB remaining lives	- RL Capex 2020-21	For each Asset Class (of 12 for RBP)
[158]	RFM	RAB remaining lives	- RL Capex 2021-22	For each Asset Class (of 12 for RBP)
[159]	RFM	RAB remaining lives	- RL Capex 2022-23	For each Asset Class (of 12 for RBP)
[160]	RFM	RAB remaining lives	- RL Capex 2023-24	For each Asset Class (of 12 for RBP)
[161]	RFM	RAB remaining lives	- RL Capex 2024-25	For each Asset Class (of 12 for RBP)
[162]	RFM	RAB remaining lives	- RL Capex 2025-26	For each Asset Class (of 12 for RBP)
[163]	RFM	RAB remaining lives	- RL Capex 2026-27	For each Asset Class (of 12 for RBP)
[164]	RFM	RAB remaining lives	- RL Capex 2027-28	For each Asset Class (of 12 for RBP)
[165]	RFM	RAB remaining lives	- RL Capex 2028-29	For each Asset Class (of 12 for RBP)
[166]	RFM	RAB remaining lives	- RL Capex 2029-30	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[167]	RFM	RAB remaining lives	- RL Capex 2030-31	For each Asset Class (of 12 for RBP)
[168]	RFM	RAB remaining lives	- RL Capex 2031-32	For each Asset Class (of 12 for RBP)
[169]	RFM	RAB remaining lives	- WARL	For each Asset Class (of 12 for RBP)
[170]	RFM	TAB remaining lives	Weighted Average Remaining Tax Asset Life - based on year-by-year tracked capex	
[171]	RFM	TAB remaining lives	- Value of net addition ($nominal)	For each Asset Class (of 12 for RBP)
[172]	RFM	TAB remaining lives	- Tax asset life	For each Asset Class (of 12 for RBP)
[173]	RFM	TAB remaining lives	- Value of TAB adjustment ($nominal)	For each Asset Class (of 12 for RBP)
[174]	RFM	TAB remaining lives	- Remaining life of TAB adjustment	For each Asset Class (of 12 for RBP)
[175]	RFM	TAB remaining lives	- Depreciated TAB adjustments	For each Asset Class (of 12 for RBP)
[176]	RFM	TAB remaining lives	- Depreciated starting RAB	For each Asset Class (of 12 for RBP)
[177]	RFM	TAB remaining lives	- Depreciated Net Capex 2012-13	For each Asset Class (of 12 for RBP)
[178]	RFM	TAB remaining lives	- Depreciated Net Capex 2013-14	For each Asset Class (of 12 for RBP)
[179]	RFM	TAB remaining lives	- Depreciated Net Capex 2014-15	For each Asset Class (of 12 for RBP)
[180]	RFM	TAB remaining lives	- Depreciated Net Capex 2015-16	For each Asset Class (of 12 for RBP)
[181]	RFM	TAB remaining lives	- Depreciated Net Capex 2016-17	For each Asset Class (of 12 for RBP)
[182]	RFM	TAB remaining lives	- Depreciated Net Capex 2017-18	For each Asset Class (of 12 for RBP)
[183]	RFM	TAB remaining lives	- Depreciated Net Capex 2018-19	For each Asset Class (of 12 for RBP)
[184]	RFM	TAB remaining lives	- Depreciated Net Capex 2019-20	For each Asset Class (of 12 for RBP)
[185]	RFM	TAB remaining lives	- Depreciated Net Capex 2020-21	For each Asset Class (of 12 for RBP)
[186]	RFM	TAB remaining lives	- Depreciated Net Capex 2021-22	For each Asset Class (of 12 for RBP)
[187]	RFM	TAB remaining lives	- Depreciated Net Capex 2022-23	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[188]	RFM	TAB remaining lives	- Depreciated Net Capex 2023-24	For each Asset Class (of 12 for RBP)
[189]	RFM	TAB remaining lives	- Depreciated Net Capex 2024-25	For each Asset Class (of 12 for RBP)
[190]	RFM	TAB remaining lives	- Depreciated Net Capex 2025-26	For each Asset Class (of 12 for RBP)
[191]	RFM	TAB remaining lives	- Depreciated Net Capex 2026-27	For each Asset Class (of 12 for RBP)
[192]	RFM	TAB remaining lives	- Depreciated Net Capex 2027-28	For each Asset Class (of 12 for RBP)
[193]	RFM	TAB remaining lives	- Depreciated Net Capex 2028-29	For each Asset Class (of 12 for RBP)
[194]	RFM	TAB remaining lives	- Depreciated Net Capex 2029-30	For each Asset Class (of 12 for RBP)
[195]	RFM	TAB remaining lives	- Depreciated Net Capex 2030-31	For each Asset Class (of 12 for RBP)
[196]	RFM	TAB remaining lives	- Depreciated Net Capex 2031-32	For each Asset Class (of 12 for RBP)
[197]	RFM	TAB remaining lives	- RL TAB adjustments	For each Asset Class (of 12 for RBP)
[198]	RFM	TAB remaining lives	- RL Start TAB	For each Asset Class (of 12 for RBP)
[199]	RFM	TAB remaining lives	- RL Capex 2012-13	For each Asset Class (of 12 for RBP)
[200]	RFM	TAB remaining lives	- RL Capex 2013-14	For each Asset Class (of 12 for RBP)
[201]	RFM	TAB remaining lives	- RL Capex 2014-15	For each Asset Class (of 12 for RBP)
[202]	RFM	TAB remaining lives	- RL Capex 2015-16	For each Asset Class (of 12 for RBP)
[203]	RFM	TAB remaining lives	- RL Capex 2016-17	For each Asset Class (of 12 for RBP)
[204]	RFM	TAB remaining lives	- RL Capex 2017-18	For each Asset Class (of 12 for RBP)
[205]	RFM	TAB remaining lives	- RL Capex 2018-19	For each Asset Class (of 12 for RBP)
[206]	RFM	TAB remaining lives	- RL Capex 2019-20	For each Asset Class (of 12 for RBP)
[207]	RFM	TAB remaining lives	- RL Capex 2020-21	For each Asset Class (of 12 for RBP)
[208]	RFM	TAB remaining lives	- RL Capex 2021-22	For each Asset Class (of 12 for RBP)
[209]	RFM	TAB remaining lives	- RL Capex 2022-23	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[210]	RFM	TAB remaining lives	- RL Capex 2023-24	For each Asset Class (of 12 for RBP)
[211]	RFM	TAB remaining lives	- RL Capex 2024-25	For each Asset Class (of 12 for RBP)
[212]	RFM	TAB remaining lives	- RL Capex 2025-26	For each Asset Class (of 12 for RBP)
[213]	RFM	TAB remaining lives	- RL Capex 2026-27	For each Asset Class (of 12 for RBP)
[214]	RFM	TAB remaining lives	- RL Capex 2027-28	For each Asset Class (of 12 for RBP)
[215]	RFM	TAB remaining lives	- RL Capex 2028-29	For each Asset Class (of 12 for RBP)
[216]	RFM	TAB remaining lives	- RL Capex 2029-30	For each Asset Class (of 12 for RBP)
[217]	RFM	TAB remaining lives	- RL Capex 2030-31	For each Asset Class (of 12 for RBP)
[218]	RFM	TAB remaining lives	- RL Capex 2031-32	For each Asset Class (of 12 for RBP)
[219]	RFM	TAB remaining lives	- WARL	For each Asset Class (of 12 for RBP)
[220]	RFM	PTRM input summary	Opening Regulatory Asset Base for 2017-18 ($m Nominal)	
[221]	RFM	PTRM input summary	- Asset Class Name	For each Asset Class (of 12 for RBP)
[222]	RFM	PTRM input summary	- Opening Asset Value (Partially As Incurred)	For each Asset Class (of 12 for RBP)
[223]	RFM	PTRM input summary	- Opening Asset Value (As Commissioned)	For each Asset Class (of 12 for RBP)
[224]	RFM	PTRM input summary	- Average Remaining Life (Year)	For each Asset Class (of 12 for RBP)
[225]	RFM	PTRM input summary	- Standard Life (Year)	For each Asset Class (of 12 for RBP)
[226]	RFM	PTRM input summary	- Opening Tax Asset Value	For each Asset Class (of 12 for RBP)
[227]	RFM	PTRM input summary	- Average Tax Remaining Life (Year)	For each Asset Class (of 12 for RBP)
[228]	RFM	PTRM input summary	- Tax Standard Life (Year)	For each Asset Class (of 12 for RBP)
[229]	RFM	PTRM input summary	- Base Regulatory Year	For each Asset Class (of 12 for RBP)
[230]	RFM	PTRM input summary	- Length of Regulatory Control Period (Year)	For each Asset Class (of 12 for RBP)

Item	Model	Tab within model	Component	Notes
[231]	PTRM	PTRM input	Opening Regulatory Asset Base and Opening Tax Asset Base for 2017-18 ($m Nominal)	
[232]	PTRM	PTRM input	- Forecast Capital Expenditure – As Incurred ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[233]	PTRM	PTRM input	- Forecast Asset Disposal – As Incurred ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[234]	PTRM	PTRM input	- Forecast Net Capital Expenditure – As Incurred ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[235]	PTRM	PTRM input	- Forecast Capital Expenditure – As Commissioned ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[236]	PTRM	PTRM input	- Forecast Asset Disposal – As De-Commissioned ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[237]	PTRM	PTRM input	- Forecast Net Capital Expenditure – As Commissioned ($m Real 2016-17)	For each Asset Class (of 12 for RBP)
[238]	PTRM	PTRM input	Equity raising costs	
[239]	PTRM	PTRM input	Forecast Operating Expenditure ($m Real 2016-17)	
[240]	PTRM	PTRM input	- Debt raising costs	
[241]	PTRM	PTRM input	Revenue Adjustments ($m Real 2016-17)	
[242]	PTRM	PTRM input	- Total Adjustments Included as Tax Income	
[243]	PTRM	PTRM input	- Total Adjustments Included as Non-tax Income	
[244]	PTRM	PTRM input	- Total Adjustments included as Tax Expense	
[245]	PTRM	PTRM input	- Total Adjustments Included as Non-tax Expense	
[246]	PTRM	PTRM input	Tax	
[247]	PTRM	PTRM input	- Expected Corporate Tax Rate (per cent)	
[248]	PTRM	PTRM input	- Tax Loss Carried Forward From Previous Period	
[249]	PTRM	PTRM input	Cost of Capital	
[250]	PTRM	PTRM input	- Inflation Rate - WACC	
[251]	PTRM	PTRM input	- Return on Equity	
[252]	PTRM	PTRM input	- Value of Imputation Credits (gamma)	
[253]	PTRM	PTRM input	- Proportion of Debt Funding	
[254]	PTRM	PTRM input	- Trailing Average Portfolio Return on Debt	
[255]	PTRM	PTRM input	Debt and Equity Raising Costs – Transaction Costs (per cent)	
[256]	PTRM	PTRM input	- Imputation Credit Payout Ratio	

Item	Model	Tab within model	Component	Notes
[257]	PTRM	PTRM input	- Subsequent Equity Raising Costs	
[258]	PTRM	PTRM input	- Dividend Reinvestment Plan Costs	
[259]	PTRM	PTRM input	- Dividend Reinvestment Plan Take Up	
[260]	PTRM	PTRM input	- Debt Raising Costs	
[261]	PTRM	PTRM input	Maximum Allowed Revenue for 2016-17 ($m Nominal)	
[262]	PTRM	PTRM input	- Current Maximum Allowed Revenue	
[263]	PTRM	PTRM input	Energy Delivered Forecast (MWh)	
[264]	PTRM	Revenue adjustment	Approved as per AER	
[265]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[266]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[267]	PTRM	Revenue adjustment	- MDQ (TJ/d)	
[268]	PTRM	Revenue adjustment	- Throughput (TJ)	
[269]	PTRM	Revenue adjustment	- No of days in a year (Days)	
[270]	PTRM	Revenue adjustment	- Capacity ($m)	
[271]	PTRM	Revenue adjustment	- Throughput ($m)	
[272]	PTRM	Revenue adjustment	- Total revenue in FY17 ($m)	
[273]	PTRM	Revenue adjustment	- Revenue adjustment ($m)	
[274]	PTRM	Revenue adjustment	- Total dollar impact ($m)	
[275]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[276]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[277]	PTRM	Revenue adjustment	- 2016/17 Approved X-factor (%)	
[278]	PTRM	Revenue adjustment	- X-factor applied to FY 16/17 tariffs (%)	
[279]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[280]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[281]	PTRM	Revenue adjustment	- Capacity ($m)	

Item	Model	Tab within model	Component	Notes
[282]	PTRM	Revenue adjustment	- Throughput ($m)	
[283]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[284]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[285]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[286]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[287]	PTRM	Revenue adjustment	Amended	
[288]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[289]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[290]	PTRM	Revenue adjustment	- MDQ (TJ/d)	
[291]	PTRM	Revenue adjustment	- Throughput (TJ)	
[292]	PTRM	Revenue adjustment	- No of days in a year (Days)	
[293]	PTRM	Revenue adjustment	- Capacity ($m)	
[294]	PTRM	Revenue adjustment	- Throughput ($m)	
[295]	PTRM	Revenue adjustment	- Total revenue in FY17 ($m)	
[296]	PTRM	Revenue adjustment	- Revenue adjustment ($m)	
[297]	PTRM	Revenue adjustment	- Total dollar impact ($m)	
[298]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[299]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[300]	PTRM	Revenue adjustment	- 2016/17 Approved X-factor (%)	
[301]	PTRM	Revenue adjustment	- X-factor applied to FY 16/17 tariffs (%)	
[302]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[303]	PTRM	Revenue adjustment	- Throughput ($/GJ)	

Item	Model	Tab within model	Component	Notes
[304]	PTRM	Revenue adjustment	- Capacity ($m)	
[305]	PTRM	Revenue adjustment	- Throughput ($m)	
[306]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[307]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[308]	PTRM	Revenue adjustment	- Capacity ($/GJ)	
[309]	PTRM	Revenue adjustment	- Throughput ($/GJ)	
[310]	PTRM	WACC	Inflation Rate	
[311]	PTRM	WACC	Value of Imputation Credits (gamma)	
[312]	PTRM	WACC	Proportion of Equity Funding	
[313]	PTRM	WACC	Proportion of Debt Funding	
[314]	PTRM	WACC	Post-tax Nominal Return on Equity	
[315]	PTRM	WACC	Post-tax Real Return on Equity	
[316]	PTRM	WACC	Corporate Tax Rate	
[317]	PTRM	WACC	Nominal Pre-tax Return on Debt	
[318]	PTRM	WACC	Real Pre-tax Return on Debt	
[319]	PTRM	WACC	Nominal Vanilla WACC	
[320]	PTRM	WACC	Real Vanilla WACC	
[321]	PTRM	WACC	Post-tax Nominal WACC	
[322]	PTRM	WACC	Post-tax Real WACC	
[323]	PTRM	WACC	Pre-tax Nominal WACC	
[324]	PTRM	WACC	Pre-tax Real WACC	
[325]	PTRM	WACC	Nominal Tax Allowance	
[326]	PTRM	WACC	Real Tax Allowance	
[327]	PTRM	WACC	Effective Tax Rate for Equity (from relevant cashflows)	
[328]	PTRM	WACC	Effective Tax Rate for Debt (effective debt shield)	
[329]	PTRM	Tables	Return on capital (nominal $)	
[330]	PTRM	Tables	Return of capital (nominal $)	
[331]	PTRM	Tables	plus operating and maintenance (nominal $)	
[332]	PTRM	Tables	plus revenue adjustments (nominal $)	
[333]	PTRM	Tables	plus net tax allowance (nominal $)	
[334]	PTRM	Tables	Smoothed revenue path (nominal $)	
[335]	PTRM	Tables	X factors tariff revenue (%) (nominal $)	
[336]	PTRM	Tables	Opening capital base (nominal $)	
[337]	PTRM	Tables	Plus net conforming capex (nominal $)	
[338]	PTRM	Tables	Plus speculative capex (nominal $)	

Item	Model	Tab within model	Component	Notes
[339]	PTRM	Tables	Plus reused redundant assets (nominal $)	
[340]	PTRM	Tables	Less depreciation (nominal $)	
[341]	PTRM	Tables	Plus indexation (nominal $)	
[342]	PTRM	Tables	Adjustment for previous period (nominal $)	
[343]	PTRM	Tables	Closing capital base (nominal $)	
[344]	PTRM	Tables	Forecast capex over access arrangement period	For each Asset Class (of 12 for RBP), (forecast, real)
[345]	PTRM	Tables	Straight-line depreciation	(current period, forecast, nominal)
[346]	PTRM	Tables	Indexation	(current period, forecast, nominal)
[347]	PTRM	Tables	Regulatory depreciation	(current period, forecast, nominal)
[348]	PTRM	Tables	Disposals	(forecast, nominal)
[349]	PTRM	Tables	Opening capital base	(forecast, nominal)
[350]	PTRM	Tables	plus indexation	(forecast, nominal)
[351]	PTRM	Tables	plus forecast capex	(forecast, nominal)
[352]	PTRM	Tables	less forecast depreciation	(forecast, nominal)
[353]	PTRM	Tables	less forecast disposals	(forecast, nominal)
[354]	PTRM	Tables	less forecast redundant assets	(forecast, nominal)
[355]	PTRM	Tables	Closing capital base	(forecast, nominal)
[356]	PTRM	Tables	Opening TAB	(nominal)
[357]	PTRM	Tables	Net additions	(nominal)
[358]	PTRM	Tables	Tax depreciation	(nominal)
[359]	PTRM	Tables	Closing TAB	(nominal)
[360]	PTRM	Tables	Opening TAB	(forecast, nominal)
[361]	PTRM	Tables	Net additions	(forecast, nominal)
[362]	PTRM	Tables	Tax depreciation	(forecast, nominal)
[363]	PTRM	Tables	Closing TAB	(forecast, nominal)
[364]	PTRM	Tables	Tax allowance	(forecast, nominal)
[365]	PTRM	Tables	Return on capital	(forecast, nominal)
[366]	PTRM	Tables	Straight-line depreciation	(commencing period, forecast, nominal)
[367]	PTRM	Tables	Indexation	(commencing period, forecast, nominal)
[368]	PTRM	Tables	Regulatory depreciation	(commencing period, forecast, nominal)
[369]	PTRM	Tables	Tax allowance	(forecast, nominal)
[370]	PTRM	Tables	Return on capital	(forecast, nominal)
[371]	PTRM	Tables	Return of capital	(forecast, nominal)
[372]	PTRM	Tables	plus operating and maintenance	(forecast, nominal)
[373]	PTRM	Tables	plus revenue adjustments	(forecast, nominal)

Item	Model	Tab within model	Component	Notes
[374]	PTRM	Tables	plus net tax allowance	(forecast, nominal)
[375]	PTRM	Tables	Building block revenue requirement	(forecast, nominal)
[376]	PTRM	Tables	Forecast straight line depreciation over the access arrangement period ($m, real)	For each Asset Class (of 12 for RBP)
[377]	PTRM	Tables	Remaining economic life	For each Asset Class (of 12 for RBP)
[378]	PTRM	Tables	Remaining tax asset lives	For each Asset Class (of 12 for RBP)
[379]	PTRM	Tables	Forecast straight line depreciation	
[380]	PTRM	Tables	Forecast Indexation	
[381]	PTRM	Tables	Debt raising costs	
[382]	PTRM	Tables	Forecast operating expenditure	
[383]	PTRM	Tables	Smoothed revenue path	
[384]	PTRM	Assets	Inflation Assumption (CPI % increase)	
[385]	PTRM	Assets	Cumulative Inflation Index (CPI end period)	
[386]	PTRM	Assets	Opening Regulatory Asset Base (RAB)	
[387]	PTRM	Assets	Real Net Capital Expenditure (capex)	
[388]	PTRM	Assets	Nominal Net Capex	
[389]	PTRM	Assets	Asset Values ($m Real 2016-17)	
[390]	PTRM	Assets	Real Straight-line Depreciation	For each Asset Class (of 12 for RBP)
[391]	PTRM	Assets	Real Residual RAB (end period)	
[392]	PTRM	Assets	Real Residual RAB (start period)	
[393]	PTRM	Assets	Asset Values ($m Nominal)	
[394]	PTRM	Assets	Inflation on Opening RAB	
[395]	PTRM	Assets	Nominal Straight-line Depreciation	
[396]	PTRM	Assets	Nominal Regulatory Depreciation	
[397]	PTRM	Assets	Nominal Residual RAB (end period)	
[398]	PTRM	Assets	Inflated Nominal Residual RAB (start period)	
[399]	PTRM	Assets	Tax Values ($m Nominal)	
[400]	PTRM	Assets	Tax Depreciation	For each Asset Class (of 12 for RBP)
[401]	PTRM	Assets	Residual Tax Value (end period)	
[402]	PTRM	Assets	RAB roll forward	
[403]	PTRM	Assets	- Opening RAB	
[404]	PTRM	Assets	- Net Capex	
[405]	PTRM	Assets	- Straight-line Depreciation	
[406]	PTRM	Assets	- Inflation on Opening RAB	
[407]	PTRM	Assets	- Closing RAB	
[408]	PTRM	Assets	TAB roll forward	
[409]	PTRM	Assets	- Opening TAB	

Item	Model	Tab within model	Component	Notes
[410]	PTRM	Assets	- Net Capex	
[411]	PTRM	Assets	- Tax Depreciation	
[412]	PTRM	Assets	- Closing TAB	
[413]	PTRM	Analysis	Inflation Assumption (CPI % increase)	
[414]	PTRM	Analysis	Cumulative Inflation Index (CPI end period)	
[415]	PTRM	Analysis	Time Varying WACC	
[416]	PTRM	Analysis	- Time Varying Return on Debt	
[417]	PTRM	Analysis	- Time Varying Nominal Vanilla WACC	
[418]	PTRM	Analysis	- Cumulative Discount Factor	
[419]	PTRM	Analysis	- Inverse Cumulative Discount Factor	
[420]	PTRM	Analysis	Annual Building Blocks ($m Nominal)	
[421]	PTRM	Analysis	- RAB (start period)	
[422]	PTRM	Analysis	- - Equity	
[423]	PTRM	Analysis	- - Debt	
[424]	PTRM	Analysis	- Revenue Building Blocks	
[425]	PTRM	Analysis	- Nominal Vanilla WACC	
[426]	PTRM	Analysis	- Return on Capital	
[427]	PTRM	Analysis	- - Return on Equity	
[428]	PTRM	Analysis	- - Return on Debt	
[429]	PTRM	Analysis	- Return of Capital (regulatory depreciation)	
[430]	PTRM	Analysis	- Operating Expenditure	
[431]	PTRM	Analysis	- Revenue adjustments	
[432]	PTRM	Analysis	- Tax Payable	
[433]	PTRM	Analysis	- Less Value of Imputation Credits	
[434]	PTRM	Analysis	- Revenue Subtotal	
[435]	PTRM	Analysis	- Additional Tax Income calculations	
[436]	PTRM	Analysis	- - Deduct Non-Tax Income Revenue Adjustments	
[437]	PTRM	Analysis	- Revenue for Tax Assessment Subtotal	
[438]	PTRM	Analysis	- Tax Expenses	
[439]	PTRM	Analysis	- - Opex	
[440]	PTRM	Analysis	- - Tax Depreciation	
[441]	PTRM	Analysis	- - Interest	
[442]	PTRM	Analysis	- - Tax expense revenue adjustments	
[443]	PTRM	Analysis	- Total Tax Expenses	
[444]	PTRM	Analysis	- Tax Calculation	
[445]	PTRM	Analysis	- Corporate Tax Rate	
[446]	PTRM	Analysis	- Taxable Income	
[447]	PTRM	Analysis	- - Pre-tax Income	
[448]	PTRM	Analysis	- - Tax Loss Carried Forward	
[449]	PTRM	Analysis	- Tax Payable	
[450]	PTRM	Analysis	- Value of Imputation Credits	

Item	Model	Tab within model	Component	Notes
[451]	PTRM	Analysis	Cash Flow Analysis Below This Line ($m Nominal)	
[452]	PTRM	Analysis	- Net Present Values	
[453]	PTRM	Analysis	- RAB (start period)	
[454]	PTRM	Analysis	- PV for Returns on and of Asset Only	
[455]	PTRM	Analysis	- PV for Capex Only	
[456]	PTRM	Analysis	- PV for End of Period Assets	
[457]	PTRM	Analysis	- Nominal Cash Flow Analysis	
[458]	PTRM	Analysis	- Capital Expenditure	
[459]	PTRM	Analysis	- Interest Payments	
[460]	PTRM	Analysis	- Repayment of Debt	
[461]	PTRM	Analysis	- Analysis Including Revenue Adjustments	
[462]	PTRM	Analysis	- Nominal Cash Flow to Equity Holders	
[463]	PTRM	Analysis	- - Pre-tax	
[464]	PTRM	Analysis	- - Post-tax	
[465]	PTRM	Analysis	- - Post-tax + Value of Imputation Credits	
[466]	PTRM	Analysis	- Real Cash Flow to Equity	
[467]	PTRM	Analysis	- - Pre-tax	
[468]	PTRM	Analysis	- - Post-tax	
[469]	PTRM	Analysis	- - Post-tax + Value of Imputation Credits	
[470]	PTRM	Analysis	- Net Cash Flow to Debt	
[471]	PTRM	Analysis	- Cash Flow to Debt before Tax Calculation	
[472]	PTRM	Analysis	- Deduction Utilised to Reduce Tax	
[473]	PTRM	Analysis	- Unutilised Deductions Carried Forward	
[474]	PTRM	Analysis	- Net Cash Flow to Debt	
[475]	PTRM	Analysis	- Nominal Cash Flows to Assets	
[476]	PTRM	Analysis	- Cashflow to Asset	
[477]	PTRM	Analysis	- Cashflow to Asset Post-tax	
[478]	PTRM	Analysis	- Cashflow to Asset Real	
[479]	PTRM	Analysis	- Cashflow to Asset Real Post-tax	
[480]	PTRM	Analysis	- Check on Vanilla WACC Cash Flow (nominal)	
[481]	PTRM	Analysis	- Check on Vanilla WACC Cash Flow (real)	
[482]	PTRM	Analysis	- Analysis Excluding Revenue Adjustments (check target WACC is met)	
[483]	PTRM	Analysis	- Restatement of figures above	

Item	Model	Tab within model	Component	Notes
[484]	PTRM	Analysis	- Intermediate tax calculation (excluding revenue adjustmnets)	
[485]	PTRM	Analysis	- Imputation credit value (excluding revenue adjustments)	
[486]	PTRM	Analysis	- Revenue Subtotal (excluding revenue adjustments)	
[487]	PTRM	Analysis	- Taxable income before loss carried forward (excluding revenue adjustments)	
[488]	PTRM	Analysis	- Taxable income (excluding revenue adjustments)	
[489]	PTRM	Analysis	- Tax payable (excluding revenue adjustments)	
[490]	PTRM	Analysis	- Tax loss carried forward (excluding revenue adjustments)	
[491]	PTRM	Analysis	- Nominal Cash Flow to Equity Holders	
[492]	PTRM	Analysis	- - Pre-tax	
[493]	PTRM	Analysis	- - Post-tax	
[494]	PTRM	Analysis	- - Post-tax + Value of Imputation Credits	
[495]	PTRM	Analysis	- Real Cash Flow to Equity	
[496]	PTRM	Analysis	- - Pre-tax	
[497]	PTRM	Analysis	- - Post-tax	
[498]	PTRM	Analysis	- - Post-tax + Value of Imputation Credits	
[499]	PTRM	Analysis	- Net Cash Flow to Debt	
[500]	PTRM	Analysis	- Cash Flow to Debt before Tax Calculation	
[501]	PTRM	Analysis	- Deduction Utilised to Reduce Tax	
[502]	PTRM	Analysis	- Unutilised Deductions Carried Forward	
[503]	PTRM	Analysis	- Net Cash Flow to Debt	
[504]	PTRM	Analysis	- Nominal Cash Flows to Assets	
[505]	PTRM	Analysis	- Cashflow to Asset	
[506]	PTRM	Analysis	- Cashflow to Asset Post-tax	
[507]	PTRM	Analysis	- Cashflow to Asset Real	
[508]	PTRM	Analysis	- Cashflow to Asset Real Post-tax	
[509]	PTRM	Analysis	- Check on Vanilla WACC Cash Flow (nominal)	
[510]	PTRM	Analysis	- Check on Vanilla WACC Cash Flow (real)	
[511]	PTRM	Analysis	- Return on Equity - Individual Years	
[512]	PTRM	Analysis	- Return on Equity	
[513]	PTRM	Analysis	- Cashflow with Imputation	

Item	Model	Tab within model	Component	Notes
[514]	PTRM	Analysis	- Add back Capex	
[515]	PTRM	Analysis	- Less Nominal Depreciation of RAB	
[516]	PTRM	Analysis	- Add Debt Repayment	
[517]	PTRM	Analysis	- Gives Nominal Return to Equity	
[518]	PTRM	Analysis	- Less Inflation in Equity Component	
[519]	PTRM	Analysis	- Gives Real Return to Equity	
[520]	PTRM	Analysis	- %ROE (1 year)	
[521]	PTRM	Analysis	- %real ROE (1 year)	
[522]	PTRM	Analysis	- Equity at Start of Period	
[523]	PTRM	Analysis	- Return on Equity - Regulatory Control Period	
[524]	PTRM	Analysis	- Revenue	
[525]	PTRM	Analysis	- Less Opex	
[526]	PTRM	Analysis	- Less Interest	
[527]	PTRM	Analysis	- Less Tax	
[528]	PTRM	Analysis	- Plus Imputation Credits	
[529]	PTRM	Analysis	- Less Capex	
[530]	PTRM	Analysis	- Less Loan Repayments	
[531]	PTRM	Analysis	- RAB Residual Value	
[532]	PTRM	Analysis	- Post-tax Return on Equity	
[533]	PTRM	Analysis	- IRR (during regulatory control period)	
[534]	PTRM	Analysis	- Target (during regulatory control period)	
[535]	PTRM	Analysis	Summary for Generation of Graphs	
[536]	PTRM	Analysis	- Return on Capital	
[537]	PTRM	Analysis	- Opex	
[538]	PTRM	Analysis	- Revenue Adjustments	
[539]	PTRM	Analysis	- Return of Capital	
[540]	PTRM	Analysis	- Net Tax Costs	
[541]	PTRM	Analysis	- Building Block Total	
[542]	PTRM	X Factors	Discount Rates	
[543]	PTRM	X Factors	- Nominal Vanilla WACC (varying)	
[544]	PTRM	X Factors	- Cumulative Discount Rate	
[545]	PTRM	X Factors	- Inflation Assumption (CPI % increase) (constant)	
[546]	PTRM	X Factors	- Cumulative Inflation Index (CPI end period)	
[547]	PTRM	X Factors	Building Block Components ($m, Nominal)	
[548]	PTRM	X Factors	- Return on Capital	
[549]	PTRM	X Factors	- Return of Capital (regulatory depreciation)	
[550]	PTRM	X Factors	- Operating Expenditure	
[551]	PTRM	X Factors	- Revenue Adjustments	

Item	Model	Tab within model	Component	Notes
[552]	PTRM	X Factors	- Net Tax Allowance	
[553]	PTRM	X Factors	- Annual Building Block Revenue Requirement (unsmoothed)	
[554]	PTRM	X Factors	Revenue Cap Calculation ($m, Nominal)	
[555]	PTRM	X Factors	- Unsmoothed - Annual Building Block Revenue Requirement	
[556]	PTRM	X Factors	- Smoothed - Maximum Allowed Revenue	
[557]	PTRM	X Factors	- X Factors	
[558]	PTRM	Tariff Calculation	Return on Capital	
[559]	PTRM	Tariff Calculation	Return of Capital (regulatory depreciation)	
[560]	PTRM	Tariff Calculation	Operating Expenditure	
[561]	PTRM	Tariff Calculation	Revenue Adjustments	
[562]	PTRM	Tariff Calculation	Net Tax Allowance	
[563]	PTRM	Tariff Calculation	Revenue Requirements	
[564]	PTRM	Tariff Calculation	NPV @ vanilla WACC	
[565]	PTRM	Tariff Calculation	Volumes	
[566]	PTRM	Tariff Calculation	Smoothed Revenues	
[567]	PTRM	Tariff Calculation	NPV @ Vanilla WACC	
[568]	PTRM	Tariff Calculation	Demand forecast (TJ/d)	
[569]	PTRM	Tariff Calculation	Opening tariff smoothing factor	
[570]	PTRM	Tariff Calculation	- RBP - reference service	
[571]	PTRM	Tariff Calculation	Approved reference tariffs	
[572]	PTRM	Tariff Calculation	- Capacity	
[573]	PTRM	Tariff Calculation	- Throughput	
[574]	PTRM	Tariff Calculation	Approved reference tariffs	
[575]	PTRM	Tariff Calculation	- Capacity	
[576]	PTRM	Tariff Calculation	- Throughput	
[577]	PTRM	Tariff Calculation	Revenue Reconciliation Factor (RCF)	
[578]	PTRM	Revenue summary	Building Block Components ($m Nominal)	
[579]	PTRM	Revenue summary	- Return on Capital	
[580]	PTRM	Revenue summary	- Return of Capital (regulatory depreciation)	
[581]	PTRM	Revenue summary	- Operating Expenditure	
[582]	PTRM	Revenue summary	- Revenue Adjustments	
[583]	PTRM	Revenue summary	- Net Tax Allowance	
[584]	PTRM	Revenue summary	- Annual Building Block Revenue Requirement (unsmoothed)	
[585]	PTRM	Revenue summary	Revenue Smoothing ($m Nominal)	
[586]	PTRM	Revenue summary	- Maximum Allowed Revenue (smoothed)	
[587]	PTRM	Revenue summary	- X factors	

Item	Model	Tab within model	Component	Notes
[588]	PTRM	Revenue summary	Building Block Components ($m Real 2016-17)	
[589]	PTRM	Revenue summary	- Return on Capital	
[590]	PTRM	Revenue summary	- Return of Capital (regulatory depreciation)	
[591]	PTRM	Revenue summary	- Operating Expenditure	
[592]	PTRM	Revenue summary	- Revenue Adjustments	
[593]	PTRM	Revenue summary	- Net Tax Allowance	
[594]	PTRM	Revenue summary	- Annual Building Block Revenue Requirement (unsmoothed)	
[595]	PTRM	Revenue summary	Revenue Smoothing ($m Real 2016-17)	
[596]	PTRM	Revenue summary	- Maximum Allowed Revenue (smoothed)	
[597]	PTRM	Revenue summary	- X factors	
[598]	PTRM	Revenue summary	Price Path Analysis ($ Nominal)	
[599]	PTRM	Revenue summary	- Forecast Energy (GWh)	
[600]	PTRM	Revenue summary	- Maximum Allowed Revenue ($m Nominal)	
[601]	PTRM	Revenue summary	- Annual Percentage Impact on Revenues (%)	
[602]	PTRM	Revenue summary	- Price Path ($/MWh) ($/MWh)	
[603]	PTRM	Revenue summary	- Annual Percentage Impact on Prices (%)	
[604]	PTRM	Revenue summary	Price Path Analysis ($ Real 2016-17)	
[605]	PTRM	Revenue summary	- Forecast Energy (GWh)	
[606]	PTRM	Revenue summary	- Maximum Allowed Revenue ($m Real)	
[607]	PTRM	Revenue summary	- Annual Percentage Impact on Revenues (%)	
[608]	PTRM	Revenue summary	- Price Path ($/MWh)	
[609]	PTRM	Revenue summary	- Annual Percentage Impact on Prices (%)	
[610]	PTRM	Equity raising costs	RAB and Capex ($m Nominal)	
[611]	PTRM	Equity raising costs	- Opening RAB	
[612]	PTRM	Equity raising costs	- Capex	
[613]	PTRM	Equity raising costs	- Capex Rate	
[614]	PTRM	Equity raising costs	Dividend Assessment ($m Nominal)	
[615]	PTRM	Equity raising costs	- Tax Payable	
[616]	PTRM	Equity raising costs	- Dividends	
[617]	PTRM	Equity raising costs	- Dividend Reinvestment	
[618]	PTRM	Equity raising costs	Benchmark Cash Flows ($m Nominal)	
[619]	PTRM	Equity raising costs	- Revenue (smoothed)	
[620]	PTRM	Equity raising costs	- Opex	
[621]	PTRM	Equity raising costs	- Interest Payment	
[622]	PTRM	Equity raising costs	- Revenue Adjustments	

Item	Model	Tab within model	Component	Notes
[623]	PTRM	Equity raising costs	- Tax Payable	
[624]	PTRM	Equity raising costs	- Internal Cash Flow	
[625]	PTRM	Equity raising costs	- Dividends	
[626]	PTRM	Equity raising costs	- Retained Cash Flow (excl. dividend reinvestment)	
[627]	PTRM	Equity raising costs	Benchmark Capex Funding ($m Nominal)	
[628]	PTRM	Equity raising costs	- Capex Funding Requirement	
[629]	PTRM	Equity raising costs	- Debt Component	
[630]	PTRM	Equity raising costs	- Equity Component	
[631]	PTRM	Equity raising costs	- Retained Cash Flow (excl. dividend reinvestment)	
[632]	PTRM	Equity raising costs	- Equity Requirement (SEO)	
[633]	PTRM	Equity raising costs	Benchmark Capex Funding ($m Real 2016-17)	
[634]	PTRM	Equity raising costs	- Equity Component	
[635]	PTRM	Equity raising costs	- Retained Cash Flow (excl. dividend reinvestment)	
[636]	PTRM	Equity raising costs	- Equity Requirement	
[637]	PTRM	Equity raising costs	- Dividend Reinvestment	
[638]	PTRM	Equity raising costs	Equity Raising Costs ($m Real 2016-17)	
[639]	PTRM	Equity raising costs	- Dividend Reinvestment Plan Requirement	
[640]	PTRM	Equity raising costs	- External Equity (SEO) Requirement	
[641]	PTRM	Equity raising costs	- Total Equity Requirement	
[642]	PTRM	Equity raising costs	- Dividend Reinvestment Plan Costs	
[643]	PTRM	Equity raising costs	- External Equity Raising (SEO) Costs	
[644]	PTRM	Equity raising costs	- Total Equity Raising Costs	

Sources and notes:

The process to produce this list involved copying and pasting the names of individual components from two models. These two models were the roll forward model (RFM) and the post-tax revenue model (PTRM) approved by the AER in its final decision on the 2017-2022 access arrangement for the Roma to Brisbane Pipeline (RBP).

Some items listed in the third column are categories rather than components in their own right. If this is the case, components that fall within this category will be listed beneath it with a hyphen.

Some items listed in the third column are derived from other items.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP