CEG COMPETITION ECONOMISTS GROUP

Consultation on form of regulation for the SWQP

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Prepared by:
Thomas Hird
Samuel Lam

Prepared for:
Gilbert + Tobin
Address:
Barangaroo NSW 2000

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1 Introduction and summary

1. I have been retained by Gilbert + Tobin to provide a report applying the economic framework and analysis in two previous reports to the specific context of the South West Queensland Pipeline (SWQP). My letter of instruction states

> *You have previously prepared:*
>
> *a) a report titled 'Returns on investment for gas pipelines' dated October 2016, addressing certain findings in the ACCC's 2016 Gas Market Inquiry Report* [CEG (2016)]; *and*
>
> *b) a report titled 'Workably competitive outcomes for gas pipelines' dated May 2019 addressing the key economic features of workably competitive markets and the role of foundation contracts.* [CEG (2019)];
>
> *We are seeking a further report setting out your expert opinion on the following matters:*
>
> *1. What is the appropriate economic framework for identifying monopoly pricing?*
>
> *2. Having regard to the information referred to in the Discussion Paper (including findings from the ACCC's 2016 Gas Market Inquiry Report), is there evidence of monopoly pricing on the SWQP?*

2. I have prepared this expert report in accordance with the requirements of the Federal Court's Expert Evidence Practice Note (GPN-EXPT). In preparing this report I have been assisted by Mr Samuel Lam, however, the opinions expressed in this report are my own.

1.1 Summary and structure

3. This memorandum has the following structure and conclusions:

   a. Section 2 compares returns on the SWQP to returns for pipeline businesses internationally. For the reasons set out in the remainder of this report, I do not consider that *ex post* returns on a pipeline asset are informative of whether the prices on the pipeline are competitive or monopolistic. Nonetheless, I conclude that returns on the SWQP are, and have consistently been, towards the lower end of returns on similar assets. If unusually high returns compared to similar businesses were a threshold test for monopoly pricing then the SWQP would fail that threshold test.

   b. Section 3 examines the history of SWQP development, from initial construction to serve eastward flows and, following radical reshaping of the Australian gas markets, subsequent investments that have expanded capacity and the ability to serve westward flows. In that context we note:

      i. Section 3.1. At its inception, and subsequently where there was a material change in capacity/service quality on the SWQP, there was a competitive process run by or for "foundation" customers seeking long term rights to the capacity created;

      ii. Section 3.2. During each competitive processes described in section 3.1, foundation customers demanded a discount relative to full recovery of the pipeline investment over their contract period/volumes. The magnitude of that discount reflected the risk adjusted expectation of incremental revenues less costs that the pipeline could expect to achieve from other/future customers. Consequently, at the time of each major investment, investors in SWQP took on material long term demand and cost risks associated with serving future customers/contracts.

iii. Section 3.3. Foundation customers, as is normal commercial practice, sought and obtained "most favoured nation" clauses such that lower prices could not be offered to future customers (at least, not without discounting the price that foundation customers paid). Similarly, foundation customers were able to sell their own contracted capacity on the SWQP to other customers (acting as competitors to any residual capacity that the owners of the SWQP could sell).

iv. Section 3.4. Consistent with section 3.3, SWQP pricing has been anchored by foundation contract pricing. Consistent with the conclusion in sections 3.3 and 3.1., SWQP pricing to foundation and non-foundation customers alike reflects prices determined in competitive negotiations (i.e., foundation contracts are the result of effective competition and foundation contracts anchor prices for all customers on the SWQP);

v. Section 3.5. At these competitive prices SWQP might over or under recover its full investment costs over its full economic life. As in most competitive markets, the level of cost recovery on an investment ultimately depends on whether long run demand and costs are more or less favourable than expected at the time major investments were competitively sourced by foundation customers. To date, there have been large swings in the actual and expected levels of long run demand on SWQP such that, at any particular time, investors may have expected to under or over-recover the risk adjusted cost of investment in the SWQP. This is entirely consistent with the prices of SWQP being the result of effective competition.

c. Section 4 summarises sections 4 of CEG (2016) and CEG (2019) which both deal with the significant problems with superimposing regulated prices on an asset like the SWQP and, in doing so, disturbing the:

i. Competitively determined prices on SWQP; and

ii. Outcomes from competitively determined allocation of volume risk on SWQP.

1.2 Answers to questions

4. My answers to the two questions put me are as follows.

1.2.1 What is the appropriate economic framework for identifying monopoly pricing?

5. Monopoly pricing cannot be identified on the basis of *ex post* returns on investments. In isolation, whether an investment has resulted in a return above or below the cost of capital tells us nothing about whether there is, or has been, monopoly pricing.

6. Except in exceptional circumstances, competitive pricing involves an allocation of risk between the customer(s) and the investors in the capital used to produce the good or service. Investors put capital in place first and take the risk on both utilisation and market prices. This is true not just for investors in a new pipeline (or pipeline expansion), it is also true for investors in residential rental property, new restaurants, office towers etc.

7. If post investment demand and prices are high enough, the investors will more than recover the risk adjusted cost of their investment and *vice versa*. In competitive markets, unambiguously competitive pricing often results in *ex post* returns that are materially above or below the *ex-ante* risk adjusted opportunity cost of funds.

8. Unlike some markets, where there is continuous competition "within the market", for gas pipeline businesses competition tends to be "for the market". This competition occurs at the time of the initial construction of the pipeline or at times where there is a need for a major capacity expansion/change

in service quality. At these times large and sophisticated "foundation customers" can organise a tender for the construction of new capacity and, in that process, extract a competitive price for long-term foundation contracts.

9. Foundation customers can then also be a source of competition "within the market" to the extent that they can use any spare capacity under their contract to compete with the pipeline owner to provide transportation services to new customers. This competition "within the market" sits alongside other sources of substitution that shippers may have (such as gas swaps that might avoid the need to use the pipeline at all).

10. The prices (and the risk allocation) struck at the time of competition for foundation customers remain reflective of the competitive price into the future and this is true irrespective of cost and volume variations on the pipeline. This is because the competitive process generates, intrinsic to that foundation contract price path, a competitively determined long-run risk allocation for exposure to variations in future volumes and costs. Consequently, even if future volumes and costs deviate from the expected levels (i.e., expected at the time competition set the foundation contract price path and risk allocation) this does not alter the competitively determined long-term price path and risk allocation. It simply means that returns to customers and pipeline investors vary from the expected level in line with the competitively determined risk exposure and price path.

11. Exactly how customer and pipeline investor returns vary will depend on the terms of the competitively determined risk allocation negotiated in foundation contracts. For example, some foundation contracts require that prices fall if total pipeline volumes exceed predetermined thresholds while others do not. In the former case, customers bear some of the long run pipeline volume risk while in the latter case that risk is borne solely by pipeline investors.

12. In my view, the best available test for whether pipeline pricing is competitive is whether the pipeline is offering services at prices that are consistent with its foundation contract prices (noting that shorter term contracts would be expected to pay a premium to longer term contracts etc).

13. If *ex post* regulation forced variations from expected costs/volumes to alter prices (up or down) for all customers, including foundation customers, then this would mean that the competitively determined risk allocation would be null and void. If a regulator could do so accurately, then all long-run risks would be transferred to customers. Of course, a regulator cannot do so accurately because:

    a. Regulation cannot raise prices above contracted levels (and cannot force customers to pay more than they value the service at). Therefore, *ex post* regulation can only ever be applied asymmetrically with the effect that pipeline investors that struck contracts with a risk/reward element would have a negative expected present value of investment (because the regulator would confiscate any positive returns for bearing risk and pass these back to customers but could not do so when there were negative returns for bearing risk).

    b. The regulator would need to determine what expectations were at the time contracts were entered into. This would inject even greater risk of regulatory confiscation for pipeline investors attempting to enter into a competitively determined risk allocation. The investor would be faced with the prospect that the regulator would confiscate:

        i. not just any returns from higher-than-expected volumes; but

        ii. potentially also, returns the regulator incorrectly believes are higher than the levels expected at the time of the contract was set.

14. The end result of such a regime must, ultimately, be that pipelines (and expansions) would only ever be commercially negotiated with the pipeline owner taking on zero volume risk (i.e., where there is,

effectively, a revenue cap arrangement built into contracts that cover 100% of volumes on the pipeline – not just foundation customer volumes). Pipeline investors would refuse to take on residual volume risk because they would expect the regulator to confiscate any return to it from bearing that risk in the event that the volumes were higher than expected (and, potentially, even when they were not).

15. Under such a regime, there would be no benefit in being a foundation customer. The current benefit from signing a long-term contract with a pipeline owner is that the contract forces the pipeline owner to bear some (or all) future volume risk. With pipeline owners unwilling to take on that risk (due to the threat of regulatory confiscation of returns to bearing that risk) then "foundation contracts", as we know them, would cease to exist.

16. In turn, this would mean that pipelines and expansions only get built when there is so much "pent up demand" that there exists a large enough base of "foundation contracts" that either soaks up all capacity immediately or, at least, so much of that capacity that the "foundation customers" are willing to bear the risk on whether, how quickly, the residual capacity gets taken up. The end result would be lost or delayed investment and higher energy costs for end users.

1.2.2 Having regard to the information referred to in the Discussion Paper (including findings from the ACCC's 2016 Gas Market Inquiry Report), is there evidence of monopoly pricing on the SWQP?

17. For the SWQP there were significant capacity expansions where unambiguously competitive prices were set for long-term foundation contracts:

    a. The initial tender to build the SWQP which resulted in foundation contracts for around half the SWQP eastward capacity (less than half if compressed);

    b. A subsequent tender held by Origin to provide north south capacity in the Australian market where the SWQP was one of three tenderers and was ultimately successful.

18. The prices struck in each of these tenders were unambiguously competitive. Moreover, in each of these prices there was embedded a competitively determined risk allocation between foundation customers and the pipeline investor. Pipeline investors offered prices to foundation customers that were based on an estimated value of future (as yet uncontracted) demand.

19. If future demand was sufficiently high then the pipeline investor could make super normal profits. But, equally, if pipeline demand was sufficiently low, the pipeline investor could make below cost (or even negative) returns. To the extent that competitively negotiated foundation contract prices were independent of future total pipeline volumes, the foundation customers were insulated from this volume risk.

20. In and around 2007, demand for eastward flows on the SWQP were so low that investors were plausibly expecting to make low or even negative equity returns on their investment. Subsequent, increased demand for westward flows, at the cost of significant investment, has improved the financial outlook for SWQP investors.

21. This illustrates why *ex post* estimates of returns cannot be used to assess competitive pricing. Depending on when a snapshot is taken, competitively determined prices could be generating high or low returns.

22. What is important is that SWQP pricing for non-foundation customers has been anchored to the foundation contracts. This was true when the SWQP was predominantly providing eastward services and is currently true when the SWQP is predominantly providing westward services.

23. These prices reflect the prices set during "competition for the market" at the time of the relevant tenders but they also reflect competition "within the market" - noting that foundation customers can and do use their contracted capacity to supply transport services to third parties on the SWQP in direct competition to the owner of the SWQP providing the same service.

24. In my view, so long as SWQP prices are anchored to foundation contract prices the only reasonable conclusion is that those prices are consistent with competitive market pricing.

25. There is no evidence in the AER discussion paper that would contradict or undermine this conclusion. The only evidence referred to in that document is somewhat the following passage:

> *Trends in the prices of services on the SWQP may help us assess the extent to which APA may hold and be exercising market power in the supply of services on the SWQP and assess how full regulation could affect the terms and conditions of access.*
>
> *In its 2016 Gas Market Inquiry Report, the ACCC found evidence of monopoly pricing on many pipelines, including for services on the SWQP.[27] Subsequently, and as recently as December 2023, the ACCC reported that it is likely that such monopoly pricing has continued with prices broadly increasing in line with inflation (for prices as of July 2023).[28]*
>
> 27 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 92, 103 - 111.

26. The above passage notes that "subsequently, and as recently as December 2023, the ACCC reported that it is likely that such monopoly pricing has continued…". However, there is no new analysis in those ACCC reports. The ACCC's conclusion in December 2023 relied solely on its conclusions in 2016 paired with the observation that real prices have not fallen. To the extent that there is any claim here that there is monopoly pricing on the SWQP it is that:

    a. The ACCC found that this was the case in 2016;

    b. Inflation adjusted prices haven't fallen since then; and

    c. Therefore, any monopoly pricing in 2016 must still be in place.

27. However, there is no finding by the ACCC in 2016 that SWQP prices were set at a monopoly level. The ACCC does state that the SWQP is one of ten pipelines that were engaging some practice that it deemed involved some characteristics of monopoly pricing – but the exact nature of what led the ACCC to include SWQP in this list (that covered all pipelines other than the fully contracted SEA Gas pipeline) is not explained by the ACCC.

28. The relevant ACCC 2016 passage is as conclusions as follows (emphasis added):[1]

> *To summarise, there is evidence that a large number of pipelines are taking advantage of their market power by engaging in monopoly pricing, with ten of the 11 pipelines that were investigated having been found to be engaging* ***in some or all of the behaviours outlined above, in addition to other forms of monopoly pricing****. The ten pipelines include, in no particular order, the SWQP/QSN, BWP, RBP, CGP, MSP, EGP, SEPS, MAPS, DTS and TGP.*
>
> *As this list highlights, some of the pipelines that were found to be engaging in monopoly pricing are,* ***strictly speaking, subject to some degree of competition*** *(that is, the MSP, EGP and MAPS) while others are subject to* ***full or light regulation*** *(that is, the RBP, DTS, CGP and half of the MSP). This finding reinforces the observation 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*

[1] ACCC Inquiry report, page 111.

form, is also failing to impose an effective constraint on pipeline operators, either directly through regulation or indirectly through the threat of regulation.

29. In CEG (2016) I explain why the indicia the ACCC used as "behaviours" consistent with "monopoly pricing" were deeply flawed. My conclusion in that report was that these logical flaws led the ACCC to incorrectly find that any pipeline with uncontracted capacity, including regulated pipelines, were "monopoly pricing".

30. However, consistent with my views in this report (and CEG (2016) and CEG (2019)) the ACCC's 2016 report does also state: [2]

> *In 2007, Epic and APA competed to develop a new pipeline to enable gas from Queensland to be transported into the southern states. Epic proposed reversing the flow and expanding the capacity of the SWQP and constructing the QSN, while APA proposed the construction of a new pipeline from Wallumbilla to Bulla Park. Epic ultimately won this contest, with AGL and Origin entering into foundation contracts in 2007 and 2009, respectively. The prices and other terms and conditions in these foundation contracts suggest that AGL and Origin both benefited from this competition. Ownership of the SWQP and QSN was later transferred to APA when it acquired the Hastings Diversified Utilities Fund in 2012.*
>
> *The outcomes of these two competitive processes suggest that 'competition for the market' can impose an effective constraint on the behaviour of new pipelines. It is important to recognise, however, that the effect of this competitive constraint will dissipate once the new pipeline has been developed, which is why foundation shippers tend to use competitive tension between prospective pipeline operators to negotiate long-term GTAs that protect their investments over the term of the GTA.*

31. It is not entirely clear what the ACCC meant by "competition for the market" tending to dissipate once the new pipeline has been developed. For the reasons set out in this report, including in paragraphs 10 to 16 above, I consider that foundation contract prices (and the intrinsic risk allocation embedded in those prices) remain the long run benchmark for competitive pricing on the pipeline.

32. However, other than this statement, the sentiments expressed in the above ACCC quote are entirely consistent with my views in this report.

2 Returns on the SWQP over time and relative to other pipeline businesses

2.1 Operating returns on physical assets for listed pipeline companies

33. For competitive pipelines (and, indeed, most competitive assets) returns can be expected to be volatile – both across pipelines and over time for the same pipeline. The fact that a pipeline has a high return relative to: a) other pipelines; or b) its past returns; does not imply that its pricing must be above competitive levels. Rather, this can simply be outcome of higher than expected demand for that pipeline's services in that period (and/or higher risk of operations for that pipeline). This is discussed more in section 3 and, in particular, section 3.2 below.

34. Nonetheless, it can be informative to ask what a "normal" range is for returns by pipeline businesses. In order to do so we have collected the following data:

[2] ACCC Inquiry report, page 97.

a. A set of businesses categorised as "Pipeline" businesses by Bloomberg. These include gas and petroleum pipeline businesses and mostly located in the US. There are 122 such businesses that have the relevant data in some years between 2000 and 2023. 101 of these businesses operate in the OECD and 82 of these operate in the US;

b. For each business I have collected data on:

   i. operating income;

   ii. tax liabilities;

   iii. the written down value of property plant and equipment (PPE); and

   iv. market capitalisation of the company.

35. I then take the ratio of operating income less tax (i.e., operating return on capital employed (RoCE) being returns from operations available for distribution to equity and debt funders) and the written down value of physical assets (PPE). This is calculated for every year that the business has data excluding the first and last year of listing (i.e., if the firm lists/delists during the period 2000 to 2023).[3]

36. In this analysis we do not include goodwill and other intangible assets in the denominator. This is not because we believe that the only investment that pipelines businesses make is in the value of physical assets. On the contrary, as explained in Appendix A of CEG (2016) and Appendix B of CEG (2019), we consider that investment in intangible assets (including "know how") is important for any pipeline business (and, indeed, most businesses).

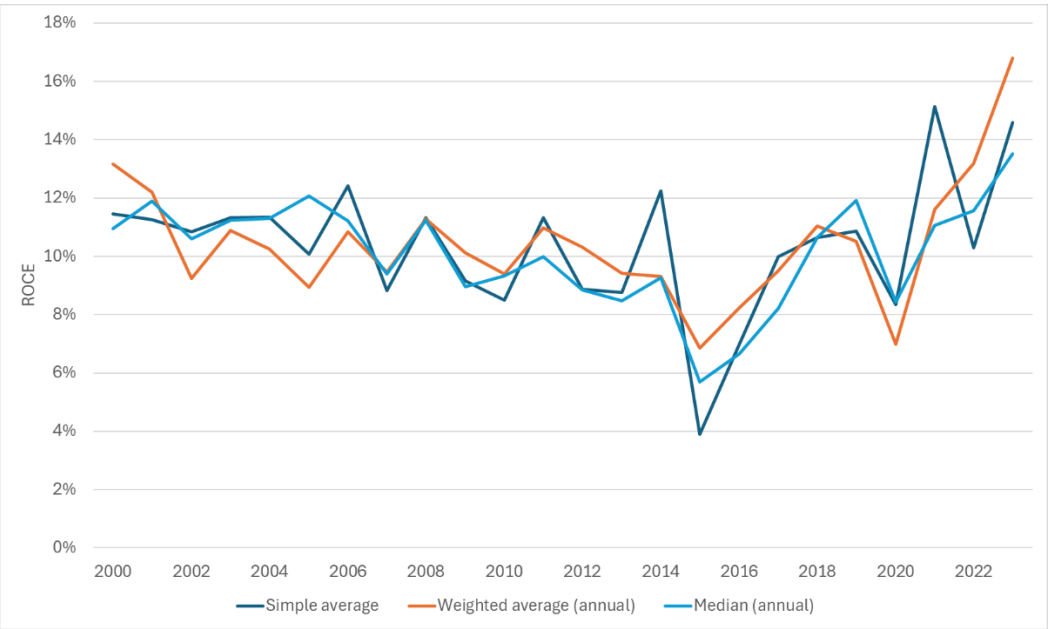
37. However, because the value of intangible assets recorded under accounting rules depends on a range of factors (such as the frequency of transactions for the asset) it is more difficult to develop a robust "apples for apples" comparison than is the case for physical assets (PPE). For the purpose of comparisons across pipelines, returns on PPE provides a more "apples for apples" comparison. However, this overstates the actual return on investment because it fails to place a value on the investment in intangible know how.

38. Figure 2-1 shows the annual simple average, median and weighted average[4] of these returns for the 82 unique US Pipeline businesses with at least one observation between 2000 and 2023 (noting that in any individual year there are less than 82 firms with data). It can be seen that, depending on the year and the metric, average annual returns vary between 4% and 17%. The average across all years is 10.6%, 10.1% and 10.5% for the simple average, median and weighted averages respectively.

[3] These data points are excluded to ensure that partial year operating income (a flow) is not compared to the stock of PPE.

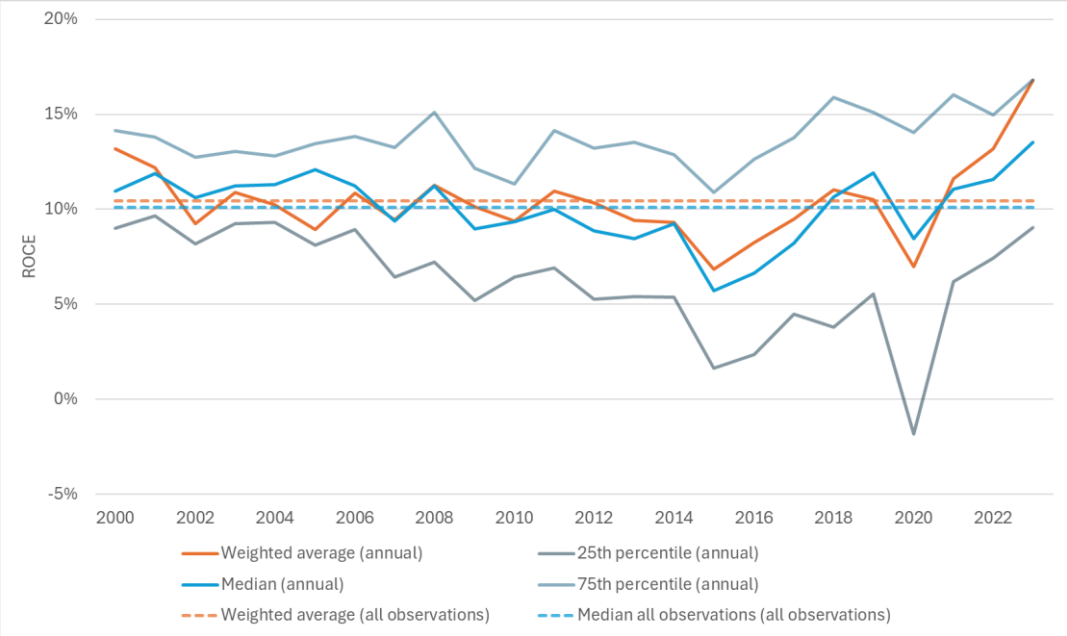
[4] Weighted by the firm's market capitalisation.

Figure 2-1: Returns after tax on US pipeline businesses – median vs weighted average



39. While these series are all quite volatile, it must be appreciated that they are averages and they disguise a much higher underlying diversity of returns for individual businesses (let alone individual pipeline assets within a portfolio of pipelines assets held by a business). Figure 2-2 shows the interquartile range of returns. On average, the interquartile range of annual returns stretches from 6.2% to 13.8%.

Figure 2-2: Interquartile range of annual US returns



40. Taking the interquartile range of US pipeline businesses as a "normal" range for return on PPE suggests that, in any given year, that range might be as high at 17% (in 2023) and as low as -2% in 2020).

41. If we extend the sample to include all OECD countries we include a further 19 firms (101 in total) and the simple average, median and weighted averages respectively become 10.3%, 9.2% and 9.6% - with the average interquartile range of 6.2% to 13.1%. If we include all countries then the simple average, median and weighted averages respectively become 10.3%, 9.8% and 9.3% - with the average interquartile range of 6.0% to 13.2%.

42. In summary, averaged over a 20-year period, a return on PPE in the range of 6% to 14% is unremarkable. It is also normal for, in any given year, returns to be below or above this range. It must also be emphasised that this analysis is performed on pipeline companies – not pipelines. Most of these companies own and operate many different pipeline assets. The range and volatility of returns on individual pipelines would be materially higher than for pipeline companies.

2.2 Operating returns for SWQP vs pipeline company returns

43. We have used APA's Financial Information Disclosure under Part 23 National Gas Rules to calculate the equivalent ROCE for the SWQP. The primary data source for deriving the time series of SWQP's ROCE was obtained from the "4. Recovered Capital" tab within the SWQP 2023 Part 23 Financial Reporting document.[5]

44. To obtain the ROCE, the below metrics are required:

    a. Revenue;

    b. Total operating expenses;

    c. Net tax liabilities;

    d. Depreciation on the fixed asset, and;

    e. Total fixed assets.

45. The ROCE for SWQP for each year is calculated using the following formula.

    Equation 1: ROCE after tax

$$ROCE = \frac{EBIT - net\ tax\ liabilities}{Total\ fixed\ asset\ less\ accumulated\ depreciation}$$

46. The "4. Recovered Capital" tab provides data since 1995 for revenue, operating expenses, leased asset interest/financing charges and net tax liabilities as well as the total capital expenditure in each year.

47. The remaining component to be estimated is depreciation in each year. Exact values for direct depreciation on the pipeline and depreciation on shared assets between 2019 and 2023 are detailed in the public financial reports.[6]

48. To estimate depreciation between 1997 and 2018, I used the "Prior Years' Accumulated Depreciation" figures reported in 2020.[7] This gives me the total depreciation of assets between 1997 and 2020. I then need to allocate that total amount to each year.

[5] https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/south-west-queensland-pipeline/, SWQP 2023 Part 23 Financial Reporting.

[6] SWQP 2023 Part 23 Financial Reporting, SWQP 2022 Part 23 Financial Reporting, SWQP 2021 Part 23 Financial Reporting and SWQP 2020 Part 23 Financial Reporting. The "3.3 Depreciation amortisation" tab.

[7] Note that, as revenue only commenced in 1997, it is assumed that there was no accounted depreciation in 1995 and 1996.

49. This yearly allocation was based on the proportion of the total asset base without depreciation for each year relative to other years.[8] For example, if there was $10 million in accumulated depreciation to be allocated over three years, with total asset bases (excluding depreciation) of $25 million, $75 million, and $100 million respectively, the accumulated depreciation is divided into ratios of 12.5%, 37.5%, and 50%.[9] This results in allocations of $1.25 million, $3.75 million, and $5 million for each of the three years, respectively.

50. EBIT was calculated in accordance with the data provided in the "2. Revenues and Expenses" tab, utilising the following formula.

Equation 2: EBIT

$$EBIT = Revenue - operating\ expenses - \text{leased asset interest (financing charges)} - \text{direct depreciation} - \text{shared asset depreciation}$$

51. ROCE less tax is calculated using the following formula.

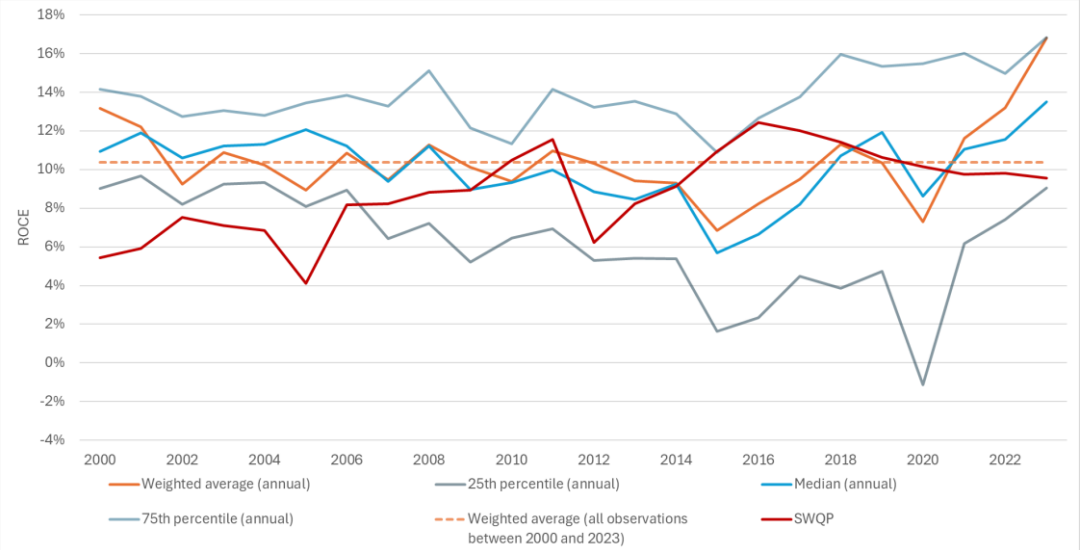
Equation 3: ROCE after tax

$$ROCE\ after\ tax = \frac{EBIT - net\ tax\ liabilities}{Total\ fixed\ asset\ less\ accumulated\ depreciation}$$

52. Finally, it should be noted that data from 1995 to 2012 are reported in calendar years, 2013 is reported for a half-year, and data from 2014 to 2023 are reported in financial years. Consequently, for periods not reported in calendar years, I estimated the calendar year ROCE and ROCE less tax by averaging the relevant metrics from two consecutive financial years. For example, the calendar year 2022 revenue is calculated based on the average of FY2022 and FY2023.[10]

53. We now compare returns on the SWQP with those on pipeline companies in our sample.

Figure 2-3: Interquartile range of annual US returns vs SWQP returns



Source: Bloomberg and APA's Financial Information Disclosure under Part 23 National Gas Rules, CEG analysis

[8] Direct depreciation and shared asset depreciation are estimated separately.

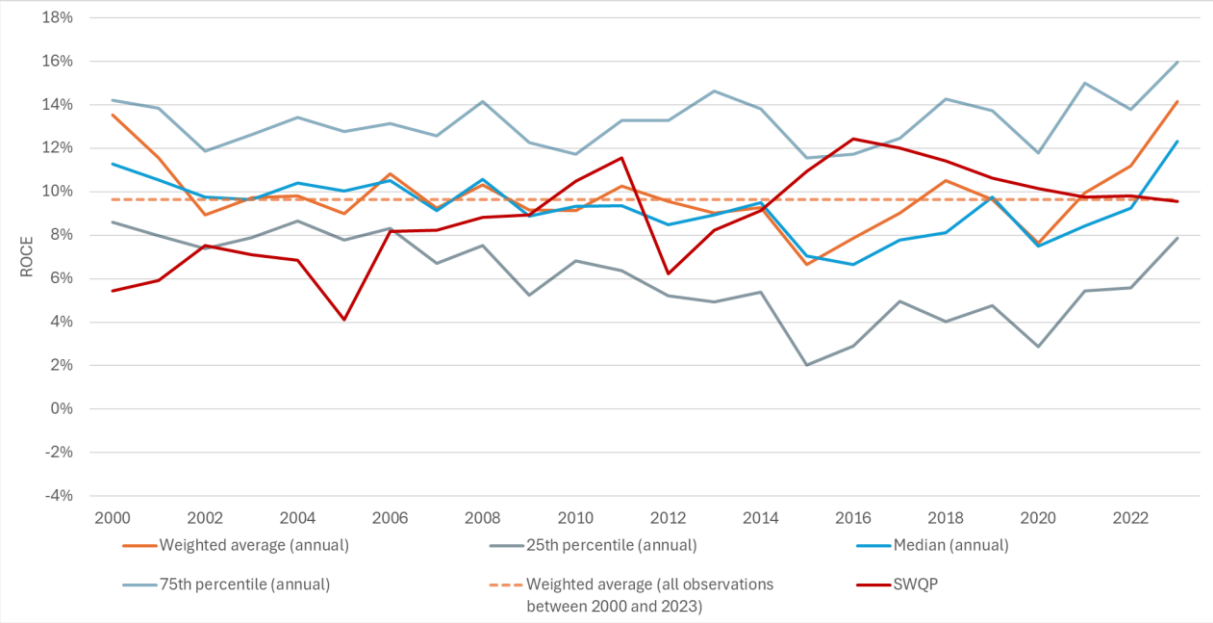
[9] For example, 12.5% = $25m / ($25m + $75m + $100m).

[10] Calendar year 2023's figure is assumed to be the same as FY2023.

54. SWQP returns have averaged 8.9% which is 1.2% to 1.7% below the average return for US pipelines (depending on how that is defined). The SWQP return has been at or below the 75th percentile of US returns in the same year but has been below the 25th percentile in multiple years. In the most recent year the SWQP return is close to the 25th percentile of US pipeline company returns.

55. Essentially the same conclusions apply if the full sample of all pipeline companies in all countries is used as can be seen in Figure 2-4 below.

Figure 2-4: Interquartile range of annual returns for the full sample vs SWQP returns



Source: Bloomberg and APA's Financial Information Disclosure under Part 23 National Gas Rules, CEG analysis

2.3 Conclusion

56. For the reasons set out in the remainder of this report, I do not consider that *ex post* returns on a pipeline asset are informative of whether the prices on the pipeline are competitive or monopolistic. Nonetheless, I conclude that returns on the SWQP are, and have consistently been, towards the lower end of returns on similar assets. If unusually high returns compared to similar businesses were a threshold test for monopoly pricing then the SWQP would fail that threshold test.

3 History of competitive pricing and volume risk allocation on the SWQP

3.1 Foundation customers create competition "for the market"

57. Section 3 of CEG (2019) describes the conditions necessary to observe competitive pricing for a service. As explained in section 3.3 (and Demsetz 1986)[11], the ultimate source of monopoly power is not simply monopoly structure (i.e., large economies of scale relative to the market). Rather, monopoly power exists where there is monopoly structure and where there are a large number of small customers with high costs of coordinating. Monopoly structure combined with a small number

[11] Harold Demsetz, Why Regulate Utilities?, Journal of Law and Economics, Vol. 11, No. 1, (Apr., 1968),

of large, sophisticated customers who can coordinate will tend to be characterised by "competition for the market".

58. This is a fundamental difference between gas transmission and gas distribution. Privately negotiated prices in gas distribution are very likely to reflect monopoly power (unless there is inefficient duplication of overlapping supply systems). By contrast, privately negotiated gas transmission contracts can, and do, reflect the outcomes of a competitive negotiation that has been organised and run by a large "foundation" customer or group of customers.

59. In the context of the SWQP, in the early 1990s the Queensland Government ran a competitive tender on behalf of shippers seeking to transport gas east from the Cooper Basin to south east Queensland. The competitive tender process involved, inter alia, the tenderer's bidding on:

    a. What price and non-price terms would be provided to foundation customers for a given capacity and a given contract term;

    b. What residual actual and potential (with further investment) capacity would be available to the successful tender to sell to other future customers if, and when, there was demand for such services. This resulted in the successful bidder being exposed to volume and cost risk associated with:

        i. Incremental sales on uncontracted capacity on the pipeline as initially constructed; and

        ii. Incremental sales on any future new capacity associated with major new investments.

60. Tenneco won this tender and began building the SWQP in 1995. Over the subsequent decade the SWQP had relatively poor financial performance (discussed in more detail in section 3.2.2.1) due to low demand for eastward transport.

61. However, there was then growing demand for westward flows to facilitate transport of newly developed coal seam gas (CSG) fields from eastern Queensland to southern states via the SWQP and some combination of other north south pipelines. As a result of this increased demand for westward flows:

    a. Circa 2008 AGL negotiated that the owners of the SWQP would build the QSN link which linked western end of the SWQP in Ballera (in Queensland) with the northern ends of the MSP and MAPS in Moomba (in South Australia) and additional compression on the eastern end to allow western flows. The construction cost for the QSN link was circa $170m. [redacted]

    b. Circa 2011 Origin held a tender for solutions that would allow it to ship gas from eastern Queensland CSG fields to southern states. There were three tenderers including one by the owners of the SWQP (and, in effect, AGL which owned the right to expand capacity on the QSN Link under its foundation contract) that involved looping the SWQP.[12] The SWQP option was successful and construction costs of around $900m in 2012.

62. As was the case in the original tender to build the SWQP, the competitive tender process to expand the SWQP involved tenderer's bidding on:

    a. What price and non-price terms would be provided to foundation customers for a given capacity and a given contract term;

[12] The other competing proposals were from APA (not yet the owner of the SWQP) which proposed a new pipeline between Wallumbilla to a mid-point on the MSP; and a Hunter Valley Pipeline consortium proposed a new pipeline from Wallumbilla to Newcastle.

b. What residual actual and potential (with further investment) capacity would be available to the successful tenderer to sell to other future customers if, and when, there was demand for such services. This resulted in the successful bidder being exposed to volume and cost risk associated with:

   i. Incremental sales on uncontracted capacity on the pipeline as initially constructed; and

   ii. Incremental sales on any future new capacity associated with major new investments.

3.2 Foundation customers demand prices set below full cost recovery based on the then expectation of uncontracted future sales

3.2.1 Conceptual discussion and illustration

63. At the time of a pipeline's construction (or major capacity expansion) foundation customers seek to gain the lowest firm capacity prices by ensuring that there is competition between potential suppliers of new capacity. In order to offer the lowest prices to the foundation customers, potential suppliers need to discount those prices by the amount of profit that they think they will be able to generate from other customers.

64. A very simple example can be used to illustrate this dynamic. Let there be a set of foundation customers who run a tender to supply 1TJ of gas transport per day for the next 50 years. Let there be three bidders who all have the same expected cost of building a running the relevant pipeline assets. Each bidder is of the view that it will cost $10bn in present value terms to build and operate a pipeline that will serve the foundation customers.

65. The only difference between the bidders relates to their expectations of future demand from non-foundation customers. All bidders place positive probability on profitably serving future demand and that this will be served by some combination of initial "overbuild" of the pipeline and future expansions of the pipeline.

   a. Bidder A estimates that serving non-foundation customers will raise the present value of actuarially expected total pipeline costs by $3bn (from $10bn to $13bn) but that it will be able to generate $5bn in the actuarially expected present value of additional revenues from non-foundation customers. This means Bidder A's lowest price offering to foundation customers would need to generate a present value of $8bn (=$13bn total expected pipeline costs less $5bn expected revenues from other customers).

   b. Bidder B estimates that serving non-foundation customers will raise the present value of actuarially expected total pipeline costs by $2bn (from $10bn to $12bn) and that it will be able to generate $5bn in the actuarially expected present value of additional revenues from non-foundation customers. On this basis, Bidder B's lowest price offering to foundation customers would generate a present value of $7bn (=$12bn total expected pipeline costs less $5bn expected revenues from other customers).

   c. Bidder C estimates that serving non-foundation customers will raise the present value of actuarially expected total pipeline costs by $8bn (from $10bn to $18bn) but that it will be able to generate $12bn in the actuarially expected present value of additional revenues from non-foundation customers. On this basis, Bidder C's lowest price offering to foundation customers would generate a present value of $6bn (=$18bn total expected pipeline costs less $12bn expected revenues from other customers).

66. If all bidders bid at the lowest price[13] they thought would be cover costs then Bidder C would win the tender and foundation customers would pay prices that generated $6bn in present value terms. This is 60% of the "stand alone" costs of serving just them ($10bn) and 33% of the total expected costs of the pipeline ($18bn including costs associated with investment to serve other future customers).

67. This thought experiment illustrates why it is important not to make the error of assuming that potential pipeline owners recover 100% of their pipeline costs from foundation customers. A bidder who took this strategy (e.g., bid a price of $10bn in the above thought experiment) would be profitably undercut by another bidder who offered a lower price to foundation customers on the basis of an expectation of selling some services to non-foundation customers (a price as low as $6bn in the above thought experiment).

68. This example further illustrates that it is important to recognise that the successful bidder takes on substantial volume risk associated with future demand and the cost of serving that demand. For example, imagine Bidder C won the bid with a price for foundation customers that would generate $7bn in present value of revenues (i.e., $1bn above the lowest amount expected to be profitable). However, imagine that actual circumstances turned out such that present value of:

    a. pipeline costs were $1bn higher than expected ($19bn rather than $18bn); and

    b. non-foundation customer revenues was $3bn lower than expected ($9bn rather than $12bn).

69. In this example, the pipeline investors would suffer a present value loss of $3bn (=$7bn from foundation customers plus $9bn from other customers less 19bn). Of course, the opposite could occur. Construction costs could be $1bn higher than expected and but this could be associated with $3bn higher non-foundation customer revenues ($15bn rather than $12bn). In this scenario, the investors benefit from a present value gain of $3bn (=$15bn +$7bn -$19bn).

70. What is important to acknowledge is that both of the above results (losses and gains) are consistent with competitive pricing and the allocation of risks that occur in a competitive market. Indeed, in a very real sense, the underlying service offering of a pipeline investor is only partially the provision of transportation services but is also the provision of intertemporal risk services. An important reason shippers typically do not also build and own pipeline assets is that they do not wish to be exposed to the uncertainty of future demand (and costs).

71. Foundation customers could simply build pipelines themselves. Alternatively, they could hold a tender to build a new pipeline (or new capacity on a pipeline) and retain 100% of the rights to all such capacity created. That shippers do not do so is explained by:

    a. the fact that doing so would expose shippers to long run risk associated with the future utilisation of the pipeline and this is risk that they do not want exposure to; and

    b. the fact that there are important and costly to acquire intangible assets ("know how") that are required to build and operate a pipeline. Pipeline businesses have already invested in these intangible assets (see Appendix A of CEG (2016)).

72. It follows that any assessment of the risks and costs of pipeline businesses should have regard to the reason that they exist separate from shippers (i.e., why shippers prefer foundation contracts to owning and operating the same pipelines). These two reasons are very largely those identified in the previous paragraph. Any assessment of costs and risks must have, front and centre, an analysis of long run volume risk and the cost (and value) of pipeline "know how".

[13] In reality, it is likely that all bidders would bid a price above this because, otherwise, winning the tender would deliver no expected value to their shareholders.

3.2.2 Application to SWQP

3.2.2.1 Initial construction

73. I am instructed that Tenneco's successful bid for the construction of the SWQP was associated with foundation contracts that covered approximately half (one quarter) of pipeline capacity without (with) compression. Specifically, around 66TJ/day eastward flow was contracted out of capacity for circa 129TJ/day[14] uncompressed (301TJ/day full compression)[15].

74. It is obvious, but hard to overemphasise, that Tenneco's contracted prices depended critically on its expected level of additional volumes it would be able to sell to other customers. The same is true of all other tenderers. It follows that the ultimate price that foundation customers paid reflected:

    a. A competitively determined estimate of the cost of building and operating the pipeline; and

    b. A competitively determined allocation of volume risk to the successful tenderer.

75. In this context, the successful tenderer is likely to be the tenderer who places the highest value on exposure to uncontracted volumes. In order to win the competitive tender, some or all of this expected value will be passed through into lower prices for foundation customers. Indeed, if it was the case that all tenderers had the same expected costs, the same perceived reliability, and if the tender specified the foundation contract volumes then, in that circumstance, the sole difference between tenderers would be their expectation of the value of uncontracted volumes and their willingness to reflect this in their prices for foundation contracted volumes.

76. It is also possible that the tender process did not involve a single specification of contracted volumes. In that case, a further point of difference between tenderers might have been their willingness to accept a large fraction of uncontracted capacity. For example, it may be that other tenderers offered a lower unit price than Tenneco but demanded a higher fraction of the SWQP be contracted.

77. The key point is that in order to win the tender Tenneco took on significant volume risk. If contracted volumes grew materially lower than expected Tenneco would under-recovery its costs and *vice versa*. The foundation contract price ultimately reflected a competitively determined price covering both pipeline cost and pipeline risks (including uncontracted volume risk).

78. The ACCC recognised this competitively determined price and risk allocation when it was asked by the National Competition Council to review a 20 year reference tariff on the SWQP. The ACCC noted that there was considerable uncertainty around actual future volumes on the pipeline. The foundation contracts agreed with Tenneco specified a form of risk sharing between foundation customers and Tenneco under which Tenneco would provide a credit to foundation customers if total pipeline volumes exceeded predetermined thresholds. This included a risk sharing mechanism for those customers who had contracted for longer than 5 years. The ACCC accepted these reference tariffs as reasonable.

79. In doing so, the ACCC explicitly noted that this left significant residual risk with Tenneco. For example, including the impact of revenue sharing, the ACCC modelled a return on investment of:

    a. 1% if construction costs were 10% higher than expected and volumes were consistent with the "base demand case"; but

[14] ACCC, Queensland Gas Pipeline Access Regime, Assessment of tender processes and reference tariff outcomes, A report to the National Competition Council p.25

[15] Ibid p.25

b. 11.8% if construction costs were 10% lower than expected and volumes were consistent with the "high demand case".

80. As it turns out, actual volumes on the pipeline were lower than even the ACCC's base case. This was largely due to the unanticipated (at the time Tenneco was tendering to build the SWQP) discovery and development of CSG fields in south east Queensland. This meant that demand for eastward flow on the SWQP into south east Queensland was dramatically reduced relative to expectations.

81. In 2007 and contracted volumes were essentially the same as in 1997 (circa 66TJ/day). Actual volumes were lower still as even contracted customers found it cheaper to source gas in south-east Queensland and, in so doing, avoid throughput charges. Note zero growth in contracted volumes over the first 10 years can be compared with the ACCC's "base demand case" that had demand increasing by a factor of 2.8 times over 20 years.

82. In this context, it is plausible that investors expected return on the SWQP was not just below the opportunity cost of funds but was plausibly materially negative.

3.2.2.2 AGL QSN link foundation contract

83. With demand for eastward flows on the SWQP falling to close to zero, AGL and the owners of the SWQP negotiated the construction of the QSN link – constructed in 2009. The QSN link would join the SWQP to the MSP and MAPS pipelines and facilitate southern flows of south east Queensland CSG to southern states.

84. I am instructed that, consistent with the economic circumstances facing SWQP investors, the AGL's contract was struck at relatively low prices and did not make material contribution to the existing SWQP assets. AGL also received the rights to expansions on the QSN link under its foundation contract.

85. It may be that, at the time, the owners of the SWQP purely assessed AGL's proposal on the basis of whether AGL's revenues would cover incremental costs. However, it seems plausible that providing AGL with approximately free access to existing SWQP assets involved taking a risk on the SWQP being used to facilitate even larger future volumes of gas flows from south east Queensland to southern states. That is, having built the QSN, the SWQP owners may have perceived an option value associated with the ability to bid future expansions of the enlarged SWQP system to supply additional southern gas flows. If so, this would mean that the SWQP owners built the QSN partly in order to position the SWQP to facilitate further southward flows if:

a. southern demand for gas would grow faster than southern supply of gas;

b. there would be continuing increases in supply CSG gas in south east Queensland;

c. that increased supply of CSG gas in south east Queensland would outpace demand to export that gas internationally as LNG; and

d. the SWQP would win any competitive process to supply additional southern flows of gas associated with a., b. and c.

3.2.2.3 Origin tender to build additional southern flow capacity

86. Around 2010/11, Origin ran a tender process to facilitate increased capacity for southern flows of gas from south east Queensland. There were 3 tenderers including a bid by the SWQP owners based on looping the original SWQP assets and expanding the QSN capacity. AGL's foundation contract for the QSN gave it rights over that expansion and, consequently, the SWQP bid was only possible with AGL's agreement.

87. The SWQP bid was successful and construction was carried out in 2012 at a cost of around $0.9bn.

88. As was the case in the original tender process for the SWQP's construction;

    a. The foundation contract with Origin only covered a part of the potential capacity of the looped SWQP (I am instructed that, currently, contracted capacity under the AGL and Origin foundation contracts accounts for around half of the total westbound capacity of the SWQP); and

    b. Competition with other tenderers was designed, by Origin, to ensure that Origin's prices were discounted by the value of incremental margins expected to be earned from non-Origin customers.

3.3 [redacted] MFNs

89. [redacted] "most favoured nation" clauses such that lower prices could not be offered to future customers (at least, not without discounting the price that the foundation customers paid).

90. This is standard practice in competitive markets for the supply of long lived infrastructure where the incremental cost of providing the contracted capacity (e.g., the costs of building the pipeline) is greater than the cost of selling incremental capacity (e.g. the cost of unused existing pipeline capacity and/or the costs of adding pipeline capacity via compression).

91. Without an MFN, the infrastructure owner would have a strong incentive to offer competitors to the foundation customers a materially lower price. In the ideal scenario for the pipeline owner, the same capacity would get sold twice – firstly to the foundation customers who would then have their up/downstream market share stolen by a new pipeline customer with lower transport costs.

92. For this reason, it is standard practice for MFNs to be negotiated in competitively determined foundation contracts.

93. [redacted] Once more, this is standard practice in such situations. A foundation customer paying a price for a fixed capacity will seek to fill that capacity with third party gas whenever third parties have a higher valuation on that capacity than does the foundation customer. Moreover, the foundation customer can do so without visibility by the pipeline owner (by signing agreements with third parties that are *de facto* transportation such as buying gas before the injection point and reselling it at the destination).

3.4 Competitively determined foundation contract prices anchor all other prices

94. I am instructed that subsequent SWQP pricing has been in line with foundation contract pricing. This [redacted] Moreover, as explained in sections 3.1 and 3.2, foundation contract pricing on the SWQP was determined in competitive negotiations (i.e., foundation contracts are the result of effective competition and foundation contracts anchor prices for all customers on the SWQP). It follows that all pricing on the SWQP is consistent with competitive pricing.

3.5 Under and over recovery of costs in the long run are both consistent with competitive determined pricing and volume risk allocations

95. As explained in section 3.2.1 all competitively determined prices for the use of long lived assets have, at their heart, a risk allocation between the users and the provider of the assets. The smaller the fraction of total pipeline risk that the foundation customers are willing to take on (e.g., the smaller the fraction of capacity that they cover and/or the shorter the duration of those contracts) then the greater the fraction of total cost recovery that must come from uncertain future (not yet contracted) demand.

96. A large risk allocation to the provider has two effects:

    a. First, it makes the provider's cost recovery over the life of the assets much more variable. Positive/negative deviations from expected long run demand will give rise to the appearance of, after the fact, material over/under recovery of total costs over the asset's lifetime. Of course, this is normal in all competitive markets where there is a risk allocation borne by investors (from housing to commodity exploration). When that risk crystalises in the *ex post* world it will either be to the investor's benefit of their loss. Observing benefits or losses says nothing about the competitiveness of the markets being invested in.

    b. Second, it increases unit risk for the investor. This means that the investor needs a higher average expected return on the investment just to break even. This is different to the effect in point "a" above. Effect "a" relates to the variance we expect to see around the mean of observed returns. Effect "b" states that the expected mean of the observed returns will be higher.

97. Both of these effects mean we should expect to see at least some high return investments in competitive markets where there has been a significant risk allocation to the investors/providers of the service.

98. At the opposite extreme, imagine an initial pipeline tender that stated that tenderers should offer a unit price based on foundation customers contracting for 100% of pipeline capacity over the full economic life of the pipeline. Further, imagine that the contract stated that the costs of all future expansions to capacity would be agreed and funded in advance with foundation customers – with foundation customers receiving expanded capacity in proportion to their funding of capacity expansions. If that contract structure was negotiated in a competitive tender then we would expect to see both:

    a. Much lower variation in profit rates (which would be driven largely by the pipeline owners' ability to save on construction and operational costs); and

    b. Much lower average profit rates (because volume risk would be largely removed).

99. The much lower prices and lower and more stable profit rates that would be observed in this "low risk" scenario are no more or less "competitive" than the higher and more volatiles profit rates observed when there is a large risk allocation to the investors.

100. I express no opinion on whether the post 2007 increase in demand for westward flows on the SWQP turned the SWQP from a net negative to net positive investment from the perspective of investors. As discussed in the next section, even if this could be accurately answered, it would not ultimately inform an assessment of whether prices are "competitive" (no more than a conclusion that very high

returns in residential rental property[16] imply that landlords have monopoly power in the residential property market).

101. Nonetheless, it is useful to return to the factors outlined in paragraphs 85.a to 85.d. Over the decade following the 2012 expansion in the SWQP these factors have, been *ex post* positive for the financial performance of the SWQP. However, there remain real material risks to the long term demand for SWQPs services. Many of these risks are outlined in AEMO's March 2024 Gas Statement of Opportunities. For example, AEMO states:[17]

> *Current projections indicate anticipated northern supplies will need to be developed from 2025, and uncertain supplies from 2026, to meet LNG export demand, northern domestic demand, and to support southern demand via flows on the SWQP.*

102. The long run availability of northern gas for transport south remains a risk to the SWQP. Similarly, the long run demand for gas in southern states remains a risk to the SWQP. As AEMO states: [18]

> *Policy incentives to limit future gas connections are now in place in Victoria and the Australian Capital Territory. These policies are expected to increase the rate of electrification of residential and/or commercial customers. For example, the Australian Capital Territory Government has introduced legislation to prevent new gas network connections in most areas from 8 December 2023. The Victorian Gas Substitution Roadmap Update bans new residential gas connections for developments requiring a planning permit from 1 January 2024 through amendment of the Victorian Planning Provisions.*

103. Notwithstanding higher returns associated with recent higher demand for westward flows, the SWQP remains exposed to volume risk associated with those flows.

104. The SWQP negotiated a competitively determined risk/reward trade-off for exposure to westward flow volume risk when it signed its foundation contract with Origin. In the long run, this may result in high or low returns to the SWQP depending on actual volumes (and costs).

105. SWQP won that tender, in part, by taking on that risk/reward exposure and offering Origin a lower price (based on SWQP's perceived value of serving future non-Origin customers). If another tenderer believed that future volumes were likely to be higher and/or lower risk then that tenderer would have offered Origin even lower prices.

106. Having won the tender based on a competitively determined risk/reward exposure it is my view that those competitively determined terms should not be disturbed by *ex post* regulation. The following section describes the consequences for efficient market operation if the AER does seek to disturb competitively determined risk/reward exposures.

[16] The residential rental market in a major capital city is unambiguously a competitive market where individual landlords do not hold any market power. When a property is being let, the owner of that property is competing with a large number of other properties also seeking tenants. Notwithstanding this competition, Australian rental property investors (and all residential investors) have made higher returns than all other broadly defined asset classes over the last several decades.* Rather than reflecting "monopoly power" this outcome reflects the fact that population growth has outstripped housing supply and that funding costs have fallen faster than was anticipated 15 and 25 years ago. This has led to market rents and property prices rising fast enough to deliver high returns (returns above the cost of funding) to property investors.

* See 2018 Russell Investments/ASX, Long Term Investing Report, June 2018. The ASX has since stopped publishing updates of this report. However, with strong property price growth since 2018 (www.corelogic.com.au/our-data/corelogic-indices) it is likely the very similar conclusions would be reached looking at a 16 and 26 year period ending 2023.

[17] AEMO's March 2024 Gas Statement of Opportunities, p 72.

[18] AEMO's March 2024 Gas Statement of Opportunities, pp. 24-25

4 Disturbing competitively determined prices/risk allocation with (ex post) regulatory determined prices and risk allocations

107. Sections 4 of CEG (2016) and CEG (2019) discuss the problems with, and ultimate arbitrariness of, imposing:

    a. a regulators' opinion on what is a competitive price "in current market circumstances";

    b. over the top of prices that were determined in competitive negotiations (i.e., circumstances where foundation customers had viable alternatives (including to go with an alternative tenderer)).

108. Section 3.2.2.1 in this report documented that the very low demand for SWQP services in 2007 likely led to an expectation, at that time, of very low or negative returns to investors. However, investors in SWQP had no ability to raise prices to their existing contracted customers just because cost recovery was low. This is because the risk allocation that was competitively negotiated in 1995 did not give them the right to do so.

109. The increase in westward flows following the successful completion of the SWQP looping project in 2012 has led to an increase in annual returns[19] prior to 2012 to levels more consistent with those observed internationally in recent years. Depending on modelling assumptions, the SWQP assets may, or it may not, currently be expected to generate a return that fully covers the costs of all investments since initial construction of the SWQP (inclusive of compensation for volume risk and on intangible 'know how' of the owners and operators of the assets).

110. But any empirical attempt to answer this question is highly fraught (given the need to make assumptions about historical and future risks as well as the value of intangible 'know how' and cost efficiencies). More importantly, even if this question could be accurately answered, it is largely irrelevant to an assessment of the reasonableness of current prices. This is because any difference between the present value of revenues and costs is ultimately the result of pipeline owners and foundation customers, in two separate competitive tender processes to date,[20] negotiating risk sharing agreements that turned out, after the fact, to benefit one or the other of the two groups (customers and pipeline investors).

111. There is no reason to disturb competitively determined prices just because the flip side of those prices resulted in a risk allocation that has, *ex post*, turned out to benefit one set of market participants over the other.

112. Of course, there is no regulatory action that can force customers to pay prices above the price that they contracted for and nor can regulation force customers to pay a price above their valuation of the service. Consequently, any disturbance to competitively determined prices can only ever be downward.

113. The end result of such regulatory action must be that investors in future pipelines/expansions refuse to take on risk. Put plainly:

    a. to the extent that investors believe that the regulator will eliminate the reward for bearing risk whenever that risk crystallizes in a large *ex post* benefit to investors; then

[19] On the depreciated value of PPE see Figure 3 3 in section 2.2.

[20] One to set the price for eastward flows and one to set the price for westward flows.

b. investors will refuse or limit the amount of volume and/or cost risk that they offer into competitive tenders; and

c. ultimately, shippers or other parties (e.g., insurers) will bear that risk even if they are not the best placed to absorb or manage the risk;

d. if shippers or other parties (e.g., insurers) are unwilling to bear that risk then new pipelines/capacity expansions will either not occur or will be delayed until the near term demand is sufficiently high that the investment in capacity is low risk.

e. ultimately, this will result in higher energy prices for end users.

114. In section 3.2 I have already explained that foundation customers could absorb all pipeline risk themselves. Foundation customers could simply build pipelines themselves. Alternatively, they could hold a tender to build a new pipeline (or new capacity on a pipeline) and retain 100% of the rights to all such capacity created. That shippers do not do so is explained by:

a. the fact that doing so would expose shippers to long run risk associated with the future utilisation of the pipeline and this is risk that they do not want exposure to; and

b. the fact that there are important and costly to acquire intangible assets ("know how") that are required to build and operate a pipeline. Pipeline businesses have already invested in these intangible assets (see Appendix A of CEG (2016)).

115. However, we almost never observe this conduct in the pipeline sector (or, indeed, in any sector). Instead, what we observe are commercial entities "pipeline owners" that specialise in both:

a. Taking on exposure to long turn demand and cost risk; and

b. That invest in developing the valuable 'know how' associated with building, operating and managing the timing of expansions on pipeline assets.

116. This suggests that there must be real economic value in providing these services. This further suggest that there is real economic value to be lost if the expected long run returns to offering these services, even when negotiated in a competitive market, are reduced or eliminated by an expectation of *ex post* asymmetric regulation.

117. In summary, it is important not to think statically about the impact of any regulatory intervention on existing pipeline capacity. One must think through the implications of expected regulatory interventions on the interactions between shippers and pipeline owners when negotiating new capacity.

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

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

27 March 2024

By email: [redacted]

Tom Hird
Director
Competition Economists Group

Dear Dr Hird

South West Queensland Pipeline Form of Regulation Review

We act for APA Group (**APA**) in relation to the form of regulation review recently initiated by the Australian Energy Regulator (**AER**) for the South-West Queensland Pipeline (**SWQP**). We are seeking an expert report from you regarding the relevant economic framework for identifying whether there is an exercise of market power in the provision of pipeline services.

Background

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

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

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

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

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

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

(d) the likely costs of end users.

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

On 21 February 2024, the AER announced that it will be conducting a form of regulation review for the SWQP. The AER indicated that this is the first of a series of self-initiated form of regulation reviews the AER is planning to undertake over several years. The AER says that the SWQP was chosen as the first pipeline for a review due to its importance to the east coast gas system in transporting gas between northern and southern states. The AER published a Discussion Paper for the SWQP form of regulation review on 6 March 2024. It has invited submissions by 27 March 2024.

The Discussion Paper states that, in conducting form of regulation reviews, the AER will seek to assess the level of market power of a service provider and the extent to which it may exercise this market power. In this context the Discussion Paper refers to the Australian Competition and Consumer Commission's (**ACCC**) 2016 Gas Market Inquiry Report, which found evidence of monopoly pricing on some pipelines.

Previous reports

You have previously prepared:

(a) a report titled 'Returns on investment for gas pipelines' dated October 2016, addressing certain findings in the ACCC's 2016 Gas Market Inquiry Report; and

(b) a report titled 'Workably competitive outcomes for gas pipelines' dated May 2019 addressing the key economic features of workably competitive markets and the role of foundation contracts.

Further expert report in relation to the SWQP

We are seeking a further report setting out your expert opinion on the following matters:

1 What is the appropriate economic framework for identifying monopoly pricing?

2 Having regard to the information referred to in the Discussion Paper (including findings from the ACCC's 2016 Gas Market Inquiry Report), is there evidence of monopoly pricing on the SWQP?

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

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

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

Yours sincerely
Gilbert + Tobin

Geoff Petersen
Partner
[redacted]

Appendix A: South West Queensland Pipeline background information

(a) Construction and early years of operation

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

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

In the early years of its operation, demand for services on the SWQP was relatively limited. The original capacity of the SWQP was ~130TJ/day (east), however contracted capacity over the first decades of the pipeline's history never reached this level. Starting contracted capacity was roughly half the pipeline's total capacity (around 66TJ/day), with the initial contracts mostly running through until around 2012. Consequently, realised returns in these early years were relatively low, reflecting the downside risk associated with this investment.

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

(b) QSN link and foundation AGL contract

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

At the time of this foundation contract, the SWQP was underutilised. Utilisation of contracted capacity had fallen as shippers were able to source cheaper gas from south-east Queensland. Moreover, in 2007, one of the larger SWQP shippers ( ) had decided not to renew its contract. At this time, contracted volumes were on par with the levels at the time of construction 1997 (circa 66TJ/day). Due to this under-utilisation of the, AGL had a high degree of countervailing power.

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

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

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

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(c) Expansion of the SWQP and expansion foundation contracts

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

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

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

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

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

(d) Period since 2012

In the period since 2012, the SWQP has undergone further significant expansion, reflecting changing market dynamics and increased demand for both eastern-haul services for LNG export and western-haul services to meet southern demand. While some support has been provided by long-term contracts (including the foundation contracts discussed above), the SWQP's owners (including APA) have also taken risk in undertaking major expansions of the pipeline's capacity. Currently, capacity contracted under the AGL and Origin foundation contracts accounts for around half of the total westbound capacity of the SWQP.

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

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

Appendix B: Documents provided

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