

22 August 2017

The Chairman
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

Dear Sir

Re: Submission to the AEMC Review into the scope of economic regulation applied to covered pipeline (Reference No. GPR0004)

The National Gas Objective (“NGO”) is stated as 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.”

The efficiency of the gas market and its competitiveness is distorted by natural gas transmission pipelines which are clear natural infrastructure monopolies yet operate without any effective economic regulation. Initial high tariffs are appropriate and necessarily part of the pipeline investment decision. But under the current regime, pipeline owners are able to continue charging these initial high tariffs well past the full recovery of the original investment and, in effect, are able to continually increase those charges in step with new build cost, which is the only alternative available to the market.

This review is centred around scheme pipelines. Appendix 1 shows that apart from those pipelines which are the final leg of transportation into Brisbane, Sydney & Melbourne, the major impact of the review will be whether there remains a significant economic barrier to entry of the whole of Northern Australia particularly as the Northern Gas Pipeline (“NGP”) becomes operational less than 12 months after the final recommendations of this review are tabled.

The attachment to this letter is Central's detailed response to the questions raised. This letter, however, deals with the high level issues which Central believes the details must address, namely:

- 1) New gas supplies from new provinces
- 2) The advent & consequences of functional pricing
- 3) The brave new world of a multi-lateral gas market
- 4) Asset valuation and impact on NGO.

1 New Gas Supplies

It is in the “long term interests of consumers of natural gas” that appropriately priced gas enters the market efficiently so as to maintain “reliability and security of supply of natural gas”. As has been found by the ACCC Inquiry into the East Coast Gas Market (“IECGM”) corroborated by recent market conditions there is an urgent need for new gas supplies and gas suppliers.

As the Chairman of the ACCC put it “more supply and increased diversity of supply will be important for the future competitiveness of the gas market” and also noted “New gas supply and more efficient gas markets will be equally important for enhancing competitiveness in the long term”¹.

For new supply to be caused, that supply nearly by definition will have been economically disadvantaged geographically or geologically (as a combination of both) compared with incumbent suppliers. Northern Australia, particularly the North West province of Queensland centred around Mt Isa and the Northern Territory are prime examples of the tyranny of distance inhibiting gas development. The construction of the NGP will overcome the physical separation from the market but the key to their economics remain locked to the future economic regulatory regime of the two main “scheme pipelines”

¹ Letter dated 13th April 2016 to Hon Kelly O’Dwyer MP

- the Carpentaria Gas Pipeline (the "CGP") and the Amadeus Gas Pipeline (the "AGP"). As noted², "There is evidence that a large number of existing pipelines have been engaging in monopoly pricing". A good example of this is the transportation of gas through the scheme pipelines from the Mereenie or Palm Valley gas fields to Ballera.

Despite for both the CGP or AGP:

- 1) having been built more than 15 years ago; and
- 2) the carriage is essentially "back haul".

The combined quoted tariffs are nearly 50% greater than the tariff quoted for the NGP presently under construction whilst they require no new investment. This clearly inhibits the promotion of efficiency in both the upstream and downstream markets – a major objective of the NGO.

The prime reason for this is the present asset valuation techniques and the present pricing principles (which are now inconsistent with and anomalous to Rule 569 of the National Gas Rules ("NGR")) do not adequately take account the return of capital recovered since the commissioning of the pipeline.

2 The advent and consequences of international gas pricing

As the ACCC IECGM noted ³ "All the participants in the east coast gas market are now exposed to international LNG & oil prices" and later on " The International LNG prices through the LNG netback prices, which are calculated by subtracting the costs of shipping, liquefaction and transmission from the spot or contract LNG prices".

The 6 LNG trains at Gladstone have been reported as being contracted up to an average 80% of design but each are capable of running consistently at 110% of design. In effect, nearly 1/3 of their respective design capacity is available for spot cargo which over 6 trains is nearly 2 trains worth of gas which can be diverted either to the international spot market or the domestic gas market. Using the said ACCC definition of LNG netback pricing, the essential determinant of whether that gas goes to the domestic market or the international spot market, is whether "the costs of shipping liquefaction & transmission" from the pricing point is less than or greater than "the cost of delivery gas from the pricing point to the prime domestic demand centres.

As noted earlier, there are scheme pipelines leading into 3 of the 4 prime domestic demand centres, namely the Roma & Brisbane Pipeline ("RBP"), the Marsden to Wilton pipeline and the Victorian Transmission System ("VTS").

It is critically important to the National Gas Objective ("NGO") that not only is there a consistency in pricing principles but also in the long term interests of consumers of natural gas that the gas transportation tariffs for the transmission to the city gate from the pricing point (presently Wallumbilla) is ideally less than the cost of supply liquefaction and transmission for export.

3 The Brave New World of Multi-lateral Gas Markets

The Australian domestic gas market and its infrastructure have historically been developed by bi-lateral arrangements primarily through Gas Sales Agreements ("GSAs") with Take or Pay provisions and Gas Transportation agreements ("GTAs") with Take or Pay provisions. This has worked well but with the advent of international LNG netback pricing & in particular the opening an arbitrage between spot LNG pricing and domestic pricing the market will be more fluid. If there is no such arbitrage then the gas will be exported.

The net result is that if the pipeline system is efficient, cost-effective, with spare capacity able to be utilised and storage viable, then security of supply will be obtained through the pricing signal. Essentially there will be approximately 2 LNG trains of gas that will no longer be dedicated to bi-lateral

² ACCC IECGM page 8

³ ACCC IECGM page 31

long term contracts. In this brave new world, price certainty essential to manufacturers and small gas producers will need to be obtained through futures contracts and the system will need to reflect this.

As the LNG market increasingly transitions towards a spot market, it will be the Gulf of Mexico and Gladstone that will become the LNG price makers. The spot LNG market will move away from being oil-linked to oscillating between Henry Hub pricing and the Australian domestic spot market (provided it becomes more deep and liquid).

If this were to be the case, a major new financial market in the form of the LNG Futures may well be centred in an Eastern seaboard capital city with all the obvious benefits which would flow from that.

The reform of the pipeline system to international standards must be empathetic to this future. These scheme pipelines must become another brick in the wall following the recent reforms to the non-scheme pipelines.

4 Asset Valuation & Impact on the NGO

As noted in our submission to the GMRG dated 20 July 2017, the most important contribution to the pricing disadvantage Australian domestic gas suppliers and gas consumers face is the mismatch between the actual residual asset value for existing mature pipelines, which are typically fully repaid over 15 years (consistent with the existing greenfield exemption period) and asset value for pipeline regulation, which is derived through accounting depreciation that is spread over extremely long life assets. Appendix 2 shows a simplified impact of this mismatch which essentially provides a 50% uplift to pipeline owners whom are able to charge customers as if they are rebuilding the entire east coast pipeline network every 15 years without having to actually spend any material capital expenditure.

Conclusion

The reforms to parts 8 to 12 of NGR must be part of and synergistic to the reforms considered by the GMRG so that the total system can react to the permanent change in the gas market occasioned by the advent of the LNG export facilities in Gladstone⁴. Australian manufacturers and chemical users must not be exposed to greater price and supply uncertainties merely to continue a regime that has allowed the total return on the pipeline business to be double that of the regulated electricity network operator⁵. The scheme pipelines are fundamental to the opening of the NT and Mt Isa gas provinces as new supplies become available. Regulated pipelines should not be guaranteed higher returns than unregulated. Central has legal advice that the arbitration provisions presently in the NGR are likely to be too costly and difficult for our lawyers to be able to recommend commencing arbitration (a copy of this advice is available on a confidential basis).

We urge the AEMC to consider reforms to Part 8 – 12 of the NGR to enable Australia to adapt to the natural gas market now exposed to international market forces.

Yours faithfully
CENTRAL PETROLEUM LIMITED

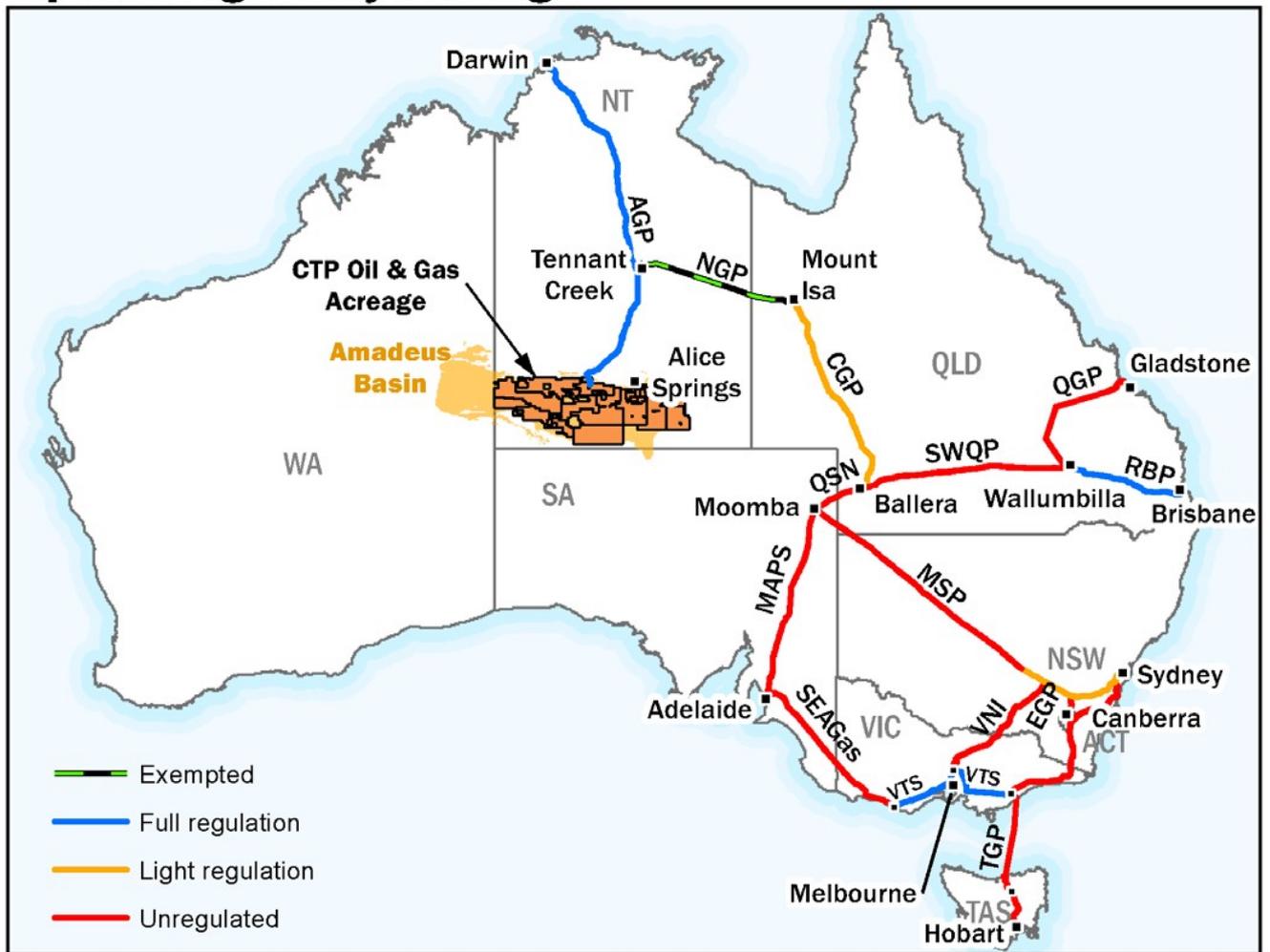


Richard Cottee
Managing Director and CEO

⁴ As such, this submission should be read in conjunction with Central's submissions to the Vertgan examination dated 18 October 2016, the initial response to the GMRG reform group dated 13 April 2017 and final submission to the GMRG dated 20 July 2017.

⁵ Vertigan Examination page 10

Pipeline regulatory coverage



Appendix 2 - Impact of Excessive Tariff Rates

Assumptions		
Asset Life	Yrs	80
Capital Recovery Period	Yrs	15
Initial Capital Investment	\$	100
Inflation Rate	%	2.5%
Risk Adjusted Market Rate of Return	%	8.0%
Monopoly Pricing Premium	%	7.0%
Annual Rate of Return for Pipeline Assets (No Economic Regulation)	%	15.0%

Fair Market Value Scenario (Economic Regulation)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
	With Economic Regulation																
Capital Related Tariff Charges																	
Return on Investment (Reasonable Market Rate of Return of 8%)	\$	-	8.0	7.8	7.6	7.4	7.1	6.8	6.4	6.0	5.5	4.9	4.3	3.6	2.9	2.0	1.1
Return of Initial Pipeline Capital Investment (15-Year Payback)	\$	(100.0)	2.1	2.5	3.0	3.5	4.1	4.7	5.3	6.1	6.8	7.7	8.6	9.6	10.7	11.9	13.2
Total Capital Related Tariff Charges	\$	-	10.1	10.4	10.6	10.9	11.2	11.5	11.7	12.0	12.3	12.6	13.0	13.3	13.6	14.0	14.3

With Economic Regulation (15-Years)

Fair Market Value with Economic Regulation* **100**

Unregulated Pricing Scenario (Monopolistic Pricing Power)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21-80	
	No Economic Regulation																						
Capital Related Tariff Charges																							
Return on Investment (Reasonable Market Rate of Return of 8%)	\$	-	8.0	7.8	7.6	7.4	7.1	6.8	6.4	6.0	5.5	4.9	4.3	3.6	2.9	2.0	1.1	-	-	-	-	-	
Return on Investment (Monopoly Pricing Premium of 7%)	\$	-	7.0	7.1	7.2	7.3	7.4	7.3	7.2	7.1	6.8	6.4	5.9	5.2	4.3	3.2	1.7	22.0	22.6	23.1	23.7	24.3	3,388.6
Return of Initial Pipeline Capital Investment (15-Year Payback)	\$	(100.0)	0.2	0.6	1.1	1.7	2.3	3.1	4.0	5.0	6.2	7.6	9.2	11.1	13.3	15.8	18.7	-	-	-	-	-	
Total Capital Related Tariff Charges	\$	-	15.2	15.6	16.0	16.4	16.8	17.2	17.6	18.1	18.5	19.0	19.5	20.0	20.5	21.0	21.5	22.0	22.6	23.1	23.7	24.3	3,388.6

No Economic Regulation (80-Years)

Asset Value to Pipeline Owner with No Economic Regulation* **272**

* NPV8 of Capital related tariff charge cash flows



Central Petroleum Limited

Response to the

**AEMC Review into the scope of
economic regulation applied to
covered pipelines**

22 August 2017

1. HOW WE GOT HERE

Following the 2016 ACCC Inquiry into the east coast gas market (IECGM) and the 2016 Examination of the Current Test for the Regulation of Gas Pipeline (Vertigan Examination), two of the most comprehensive independent examinations ever undertaken for the Australian domestic gas market, monopolistic pricing within the pipeline sector is now recognised as a major source of inefficiency within the Australian domestic gas market. This recognition validates what users of gas pipelines have long highlighted as a major distortion in gas price signals which are critical to efficient gas markets by stimulating new gas production and mitigating the magnitude of demand destruction associated with increasing gas production costs.

A number of the Vertigan Examination's recommendations were recently implemented for uncovered pipelines. The most critical of which deals with the pricing principles available under a binding arbitration framework. The pricing principles for arbitration of uncovered pipelines now specifically addresses what has essentially been a loophole in the prevailing pipeline regulations – the use of accounting depreciation in determining asset value notwithstanding the much more rapid return of capital investment ingrained within the pipeline tariff pricing regime. This loophole has had the effect of allowing pipeline owners to self-determine pipeline revenue generation year-on-year (i.e. monopolistic pricing power) without having to recognise those excessive asset returns in future pipeline tariff calculations.

Whilst this critical issue appears to now have been addressed for uncovered pipelines through the National Gas (Pipeline Access – Arbitration) Amendment Rule 2017 (section “569 – Pricing Principals”), it does not extend to covered pipelines which must continue to rely on Parts 8 – 12 of the NGR to establish pricing principals for regulated pipelines. It is these rules, specifically Part 9 – Price and revenue regulation, which allow pipeline owners to exploit a regulatory flaw and engage in monopolistic pricing behaviour. As the ACCC Inquiry states (pg. 100), “There is evidence that some pipelines that are subject to full regulation are taking advantage of the limitations in the gas access regime to exercise market power”. Failing to address this flaw within the NGR:

- 1) Fails the NGO by allowing a major inefficiency to persist within the gas market.
- 2) Creates a material gap between covered and uncovered pipelines, leading to a bizarre scenario where pipeline owners would need to seek regulatory coverage in order to preserve monopolistic pricing behaviour.

It is imperative that the relevant sections of the NGR (notably Part 9) be revised to reflect past recovery of capital and thereby contain current and future pipeline tariffs to better mirror an efficient and competitive pipeline sector.

2. WHY NOW

The NGR has been in place for a long time without the issue of monopolistic pipeline pricing becoming a featured issue. A series of events, however, have now transpired which makes pipeline pricing a material and urgent market issue:

- a) The domestic gas pipeline network was developed through bilateral supply arrangements where a gas producer and/or a gas customer underwrote the investment in a pipeline through long-term (e.g. 10-15 year) GTAs. These foundation GTAs were negotiated in a competitive contracting environment where a number of parties could compete to build, finance or own each pipeline. As such, the initial pipeline tariffs were “market efficient” and enabled the required pipeline infrastructure to develop as and when required. There was little need for, or focus on, pricing regulation during this initial stage in a pipeline’s economic life.
- b) Most of the existing pipeline network has now matured past 15 years (Appendix A). Ownership of these pipelines has now largely consolidated into a single owner entity. This entity has built very few of the pipelines it owns, but typically acquires the assets after development. These mature pipelines (>15 years) have had their initial capital cost recovered through foundation GTAs and are now operating in a phase where there is no longer an initial capital cost recovery justified – this should be (and certainly is the case in other international gas markets) a period of significant efficiency within the Australian gas market as existing pipeline infrastructure with economic lives of 50+ years can operate at very low cost.
- c) Gas pipelines, however, are natural monopolies and without effective economic regulation, pipeline owners are able to maintain pipeline tariffs at levels that maximise their profits. This drive to maximise profit occurs notwithstanding the inherent efficiencies that should be available to the gas market from existing mature pipeline networks that have already provided for a return of initial capital costs. The NGR are not currently effective at constraining the market power of pipeline owners.
- d) Concurrent with maturation of the existing pipeline network, the cost of gas production has leapfrogged several decades as significant existing gas reserves were suddenly dedicated to the LNG export market (Appendix B). The impact of increasing gas production costs on the marginal domestic gas customer has now reached a point now where the market can no longer support monopolistic pipeline pricing without severe demand destruction. This is not consistent with the NGO which “*is for the long term interest of consumers of natural gas*”. Monopolistic pricing by pipeline owners now has a heightened impact on the ex-field price signals necessary to spur investment in new gas supply and to reduce the delivered cost of gas to customers thereby minimising demand destruction in the economy.

It is within this context that the current AEMC review of the NGR Parts 8 – 12 is both timely and critical.

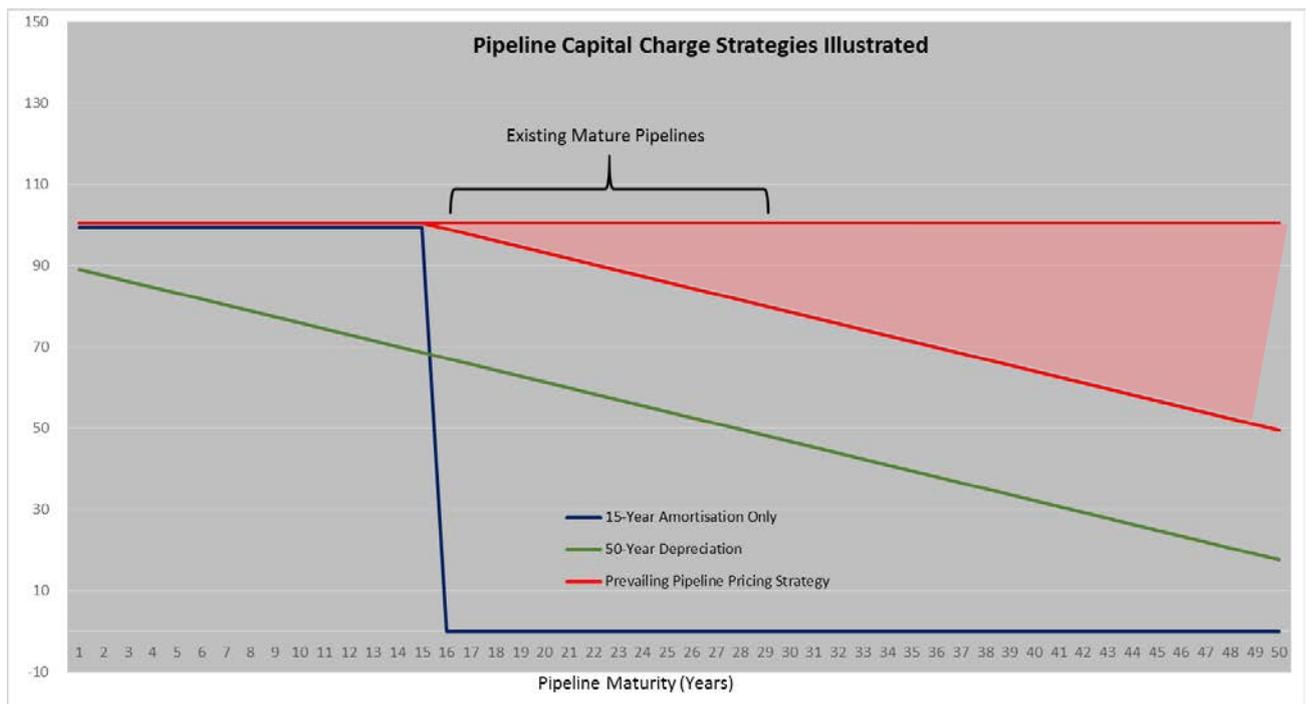
3. WHAT’S WRONG

Monopolistic pricing behaviour was evident in both the IECGM and Vertigan Examination and current pipeline regulation was noted as not being an effective deterrent to this behaviour. The IECGM (pg. 18) states “*Other gaps in the regulatory framework are also allowing pipelines that are subject to regulation to continue to engage in monopoly pricing*”. The lack of any material tariff related arbitration under the existing regulations should also be a “red flag” that they are not effective in constraining the market power of pipeline owners. The reason is simply that Part 9 (Division 3 & 4) which outlines a building block approach for regulating pipeline tariffs allows pipeline owners to fully recover the initial capital cost of a pipeline during the first 15 years, but continue to recover significant capital charges over the next 35 years of the pipeline’s economic life.

This “flaw” exists through the NGR’s reliance on depreciation in determining a pipeline’s asset value or capital base. Whilst this approach can be effective, however, it only makes sense where pipeline tariffs are regulated from day 1 such that the capital cost is slowly recovered over the depreciable life of the pipeline (typically 50 years). In this case, a pipeline’s capital costs can only be recovered at 2%/year (straight line) which results in low initial pipeline tariffs that slowly decline over 50 years. As discussed above, however, the capital cost of pipelines have historically been recovered over a much shorter period (typically 15-years) through foundation GTAs. The need for an “accelerated” capital recovery for pipelines can be attributed to:

- 1) Gas producers typically seeking to sell available reserves over periods of up to 10 – 15 years,
- 2) Gas customers typically seek to commit to gas purchases over periods up to 10 to 15 years, and
- 3) Debt capital markets are more competitive for amortisation periods up to 10 - 15 years

Gas transportation tariffs therefore tend to start at levels that amortise the full capital cost of the pipeline within 15 years. The 15-year green-field exemption serves to ensure that this shorter capital recovery period can be available for new pipeline investment. At the end of that amortisation period, however, the NGR does not prevent the pipeline owner from collecting a “capital charge” even though there is no remaining initial asset value or capital base. The strategy of continuing to charge elevated pipeline tariffs for mature pipelines (> 15 years old) is illustrated in the following chart:



The blue line above illustrates how a pipeline that is amortised over 15 years would essentially stop capital charges after year 15. The green line illustrates how capital charges start much lower and would decline under a depreciation period of 50 years. The red line, however illustrates a pricing strategy where pipeline owners continue with pipeline capital charges well after the initial 15 year amortisation period. This excessive capital charge over the life of the pipeline lead to consistent windfall gains to

the pipeline owners (Appendix C) and leads to significant pricing distortion in both the ex-field gas price observable to gas producers and the delivered gas price observable to gas customers.

4. WHAT NEEDS TO CHANGE

In order to rectify the above flaw in the NGR, the asset value or capital base used for determining permitted capital charges must recognise the actual return of capital since commissioning of the pipeline, rather than allowing mature pipelines the opportunity to value assets through depreciation. Changes to the NGR must therefore include the following:

- 1) Part 9 needs to eliminate the use of “depreciation” in determining a pipeline’s capital base, specifically under Total revenue (76), the Capital base (77) and the Projected capital base (78) as well as any other references to depreciation within the NGR (and related regulation) as it relates to the calculation of permitted capital charges.
- 2) In place of “depreciation”, the relevant sections of the NGR (and related regulation) should instead be made consistent with the National Gas (Pipeline Access – Arbitration) Amendment Rule 2017, specifically section “569 – Pricing Principles”, where the Capital Base reflects the cost of construction, less the return of capital since commissioning of the pipeline. Critically, this revised methodology for determining the capital base (and therefore the capital charge) needs make clear that 1) the starting point is the actual construction cost for each pipeline, and 2) that the capital base is reduced by the historical return of capital based on the actual financial performance of each asset since commissioning.
- 3) In order to give effect to the above, the AER should be tasked with determining what (if any) capital base or asset value remains at this time for each covered pipeline, as this specific analysis has not been performed and it will require adequate resourcing, technical expertise and information collection powers which are best provided by the AER. Once determined, market participants will (when combined with other parts of the NGR) be in a position to assess pipeline reference tariffs and the merits of seeking arbitration should that be necessary.

In addition to the critical change above, we believe that the NGR should also ensure alignment with the National Gas (Pipeline Access – Arbitration) Amendment Rule 2017 by clarifying that backhaul and other similar ancillary services are priced on a “cost of service” basis only and not as a multiple to the regulated capacity charges of the pipeline. This adjustment is important to ensure that monopolistic pricing by pipeline owners is not simply shifted from regulated capacity charges to ancillary services which do not directly utilise the capacity of a pipeline.

5. HOW DOES THIS SERVE THE NGO

The Commission’s assessment of any recommendations to amend the NGR is based on 5 key assessment criteria. How the proposed amendments support these assessment criteria is as follows:

- 1) “**Efficient investment in gas transmission and distribution pipelines,**” The pipeline sector has argued that any effective economic regulation of pipelines tariffs would impact pipeline investment. This is simply self-serving and erroneous. First, pipeline owners rarely underwrite the financial risk of a pipeline. Gas producers and/or gas customers with investment grade credit commit to long-term GTAs with fixed capacity charges that fully underwrite a new pipeline within a 15-year amortisation period. After pipelines have been built, they are then typically sold to incumbent pipeline owners who seek to maximise their profits concurrent with and beyond the foundation contracts. We note pipeline ownership is

heavily concentrated within one entity in Australia which has developed very few pipelines in its own right, but rather purchased existing pipelines *after* they were developed (Appendix D). Economic regulation will have no impact on the timing or nature of new pipeline investments, something supported by the 15-year green-field exemption. In addition, effective economic regulation can be structured to ensure pipeline owners receive full costs and a risk-adjusted market rate of return on subsequent capital investment. Whilst tariffs under effective economic regulation will be less than the windfall gains currently enjoyed by pipeline owners, they are, by definition, appropriate to ensure efficient ongoing capital expenditures are available within the pipeline sector.

“...and its promotion of efficiency in upstream and downstream markets.” The recent examinations into the Australian gas market has highlighted monopolistic pricing within the pipeline sector and noted that existing regulations are not effective as a deterrent. Excessive pipeline tariffs distort the gas price signals that are critical to efficient gas markets, dampening the ex-field gas price observable to gas producers (when new gas supplies are needed) and elevating the delivered gas price observable to gas customers (magnifying demand destruction within the economy). The proposed amendments to the NGR are a direct and significant opportunity to promote efficiency in the upstream and downstream markets in accordance with the NGO.

- 2) **“Efficient operation in gas transmission and distribution pipelines,”** Effective economic regulation ensures pipeline owners receive full cost of services and provide for reasonable incentive payments to promote innovation and efficiency gains. International experience clearly shows that an efficient and vibrant pipeline sector can operate in conjunction with effective economic regulation of pipeline tariffs. Monopolistic pipeline pricing, in and of itself, does not promote these operational outcomes or the NGO more generally.

“...and its promotion of efficiency in upstream and downstream markets.” The market power currently enjoyed by pipeline owners creates marked inefficiency within upstream and downstream markets. This is particularly visible when Australia’s gas market is compared to comparable gas markets internationally. With an existing interconnected pipeline network that is now largely mature (>15 years), Australia’s gas market should be benefitting from low-cost and highly flexible pipeline transportation arrangements. This, however, is not the case, with efficiency in the upstream and downstream markets being particularly affected. Opportunities like deep and liquid spot markets, financial derivative markets, forward curves and hedging, and gas storage all severely constrained by excessive and inflexible gas transportation costs. Section 6.4.3 and 6.4.4 of the IECGM further highlights these effects on upstream and downstream markets. The proposed amendments to Part 9 are a critical and necessary first step in allowing efficiencies within the upstream and downstream markets to materialise and evolve.

- 3) **“The utilisation of pipelines by both upstream and downstream users.”** The market power currently enjoyed by pipeline owners reduces overall utilisation of pipelines by upstream and downstream markets as lower ex-field prices reduces supply and increased delivered prices reduces demand. This outcome is particularly unfortunate in that Australia’s gas market should be well positioned at this time to benefit from an existing interconnected pipeline network that is now largely mature (>15 years). The proposed amendments to Part

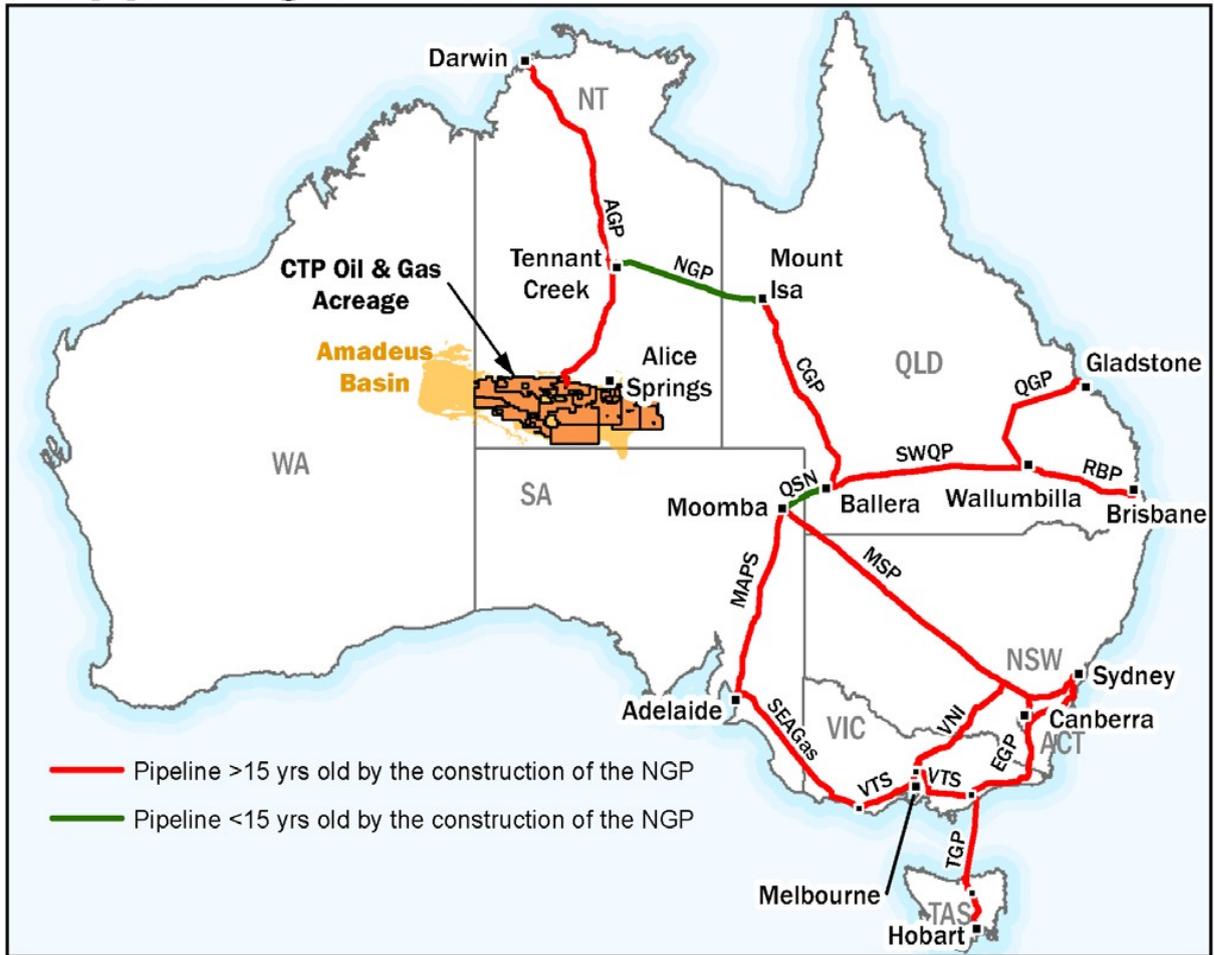
9 are critical and necessary to promoting the efficient utilisation of pipelines by both upstream and downstream markets.

- 4) ***“Gas transportation tariffs for both transmission and distribution pipelines.”*** The intent of the proposed amendments to Part 9 is to constrain the current market power of pipeline owners in setting pipeline tariffs and ultimately reduce the cost of transporting gas. This would directly support the NGO.
- 5) ***“Non-tariff terms and conditions for gas transportation on both transmission and distribution pipelines.”*** The proposed amendments to Part 9 do not directly address or adversely affect non-tariff terms and conditions. Whilst these are important in the context of an efficient domestic gas market, they are marginal considerations relative to the inability of the NGR to constrain the market power of pipeline owners and monopolistic pricing behaviour observable within the pipeline sector.

For any enquiries in relation to this submission please contact Mr Leon Devaney by email to LeonDevaney@centralpetroleum.com.au.

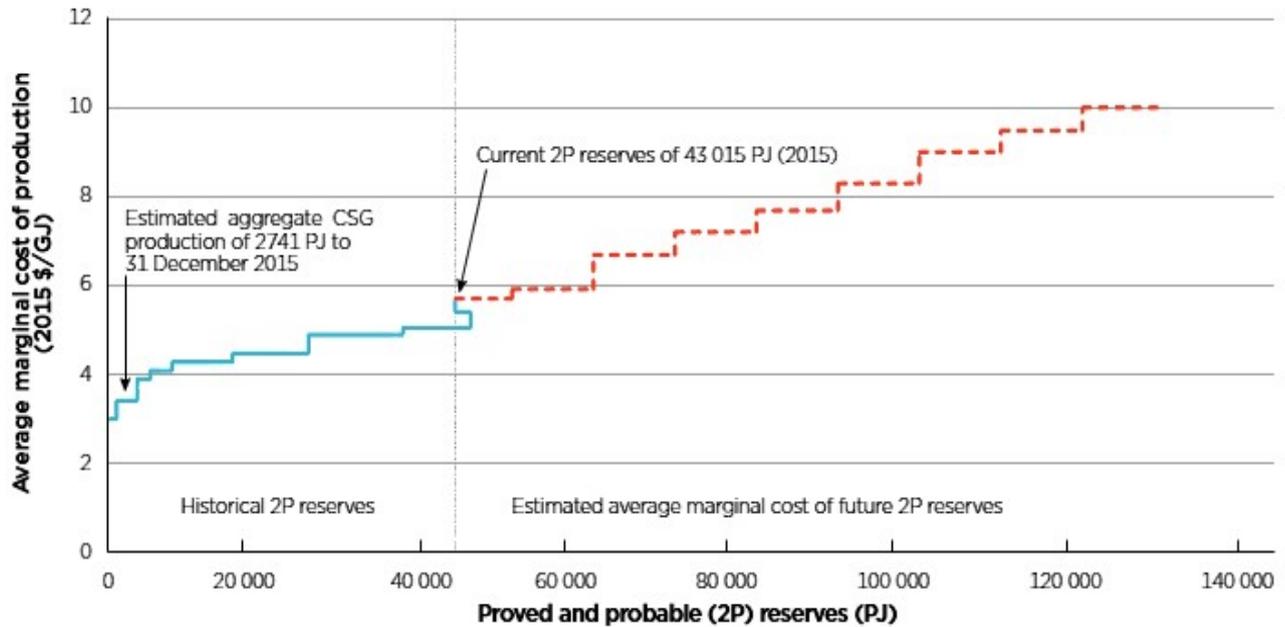
Appendix A – Gas Pipeline Maturity

Gas pipeline age in 2018



Appendix B – CSG production cost curve

Chart 1.7: CSG production cost curve in the east coast gas market as at March 2016



Source: RLMS, March 2016, commissioned by the ACCC.

Note: The kink in the chart at about the 40 000 PJ mark was caused primarily by write downs in New South Wales CSG reserves in 2014 and 2015.

Appendix C – APA

The 2016 Annual Report of APA confirms the extraordinary success of APA's pricing strategies directly attributable to the operation of the Code as confirmed by the High Court.

chairman's report.

I am pleased to report another solid year for APA. The FY2016 results represent the outcome of a consistent and prudent strategy of growth and value creation.



APA has been able to reap the benefits of this strategy, seeing earnings come through from capital we have invested in growing our asset base through acquisitions and organic expansion. The FY2016 results include a full year of earnings from the Wallumbilla Gladstone Pipeline acquired in FY2015 and increasing revenue streams from the ongoing expansion of both the East Coast Grid and expansions and greenfields investment in Western Australia.

APA's long term vision, strategic planning and focused execution have seen the business continue to deliver prudent distribution growth and long term market-leading increases in Securityholders' value.

The total distributions for FY2016 of 41.5 cents per security represent a 9.2 per cent increase over FY2015. As per our distribution policy, distributions have been fully covered by operating cash flows with an appropriate amount of those cash flows retained within the business to support growth.

Your Board believes that the increase in distributions represents a prudent increase in returns for Securityholders given the current economic environment. The Board is of the view that the 41.5 cents per security represents a solid base from which to increase distributions on a sustainable basis

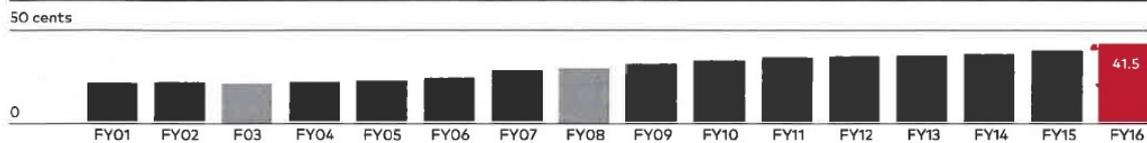
(APA 2016 Annual Report page 2, 23/09/2016)

APA financial performance is truly outstanding. The company reports a Total Shareholder Return of 16.7% for FY2016. This would be highly creditable for a growth company, but is an extraordinary return for a long lived infrastructure owner with its self-described "low risk, resilient business model"¹. It would be interesting to compare this with either equivalent domestic gas suppliers or industrial consumers where gas accounts for 40% of the input costs, or the chemical producers where gas cost accounts for up to 80%².

Moreover, APA's financial performance is not a 'one-off' result. As the APA Chairman notes, the company has provided a Compound Annual Growth Rate of shareholder returns since 2000 of 19.1% and distributions to shareholders increase every year.

¹ APA Annual Report – Chairman's Address

² Page 3, ABC News transcript of 19 September 2016

APA'S HISTORICAL ANNUAL DISTRIBUTIONS (CENTS PER SECURITY), HAS CONTINUED TO INCREASE


(In the pipeline - APA Group 2016 annual results summary, September 2016)

This may represent an international record for returns on infrastructure investment in a mature market. As Central Petroleum contends in this submission, these pipelines are a transport system which is protected from market forces by their unregulated monopoly status under the protection of the Code.

It is further noteworthy that the APA does not construct new pipelines with the exception of the VNI. Most of its network was either inherited by the spinoff from AGL or acquired through the evolution of its current company structure. Since 2000 APA has not constructed any major new pipeline, although it has invested in some pipeline maintenance and improvements. It follows that APA's dominant market position has not led to investment and the extension or development of the Australian pipeline network. Neither can APA's extraordinary financial success be attributed to its development of new pipelines (refer Appendix D).

The APA's report confirms the benefits it acquired from pipeline integration

The Benefits and Costs of Integration in Transmission/Transportation Networks report was prepared by The Brattle Group for APA Group in August 2016. The report looks and the benefits and costs of integration in APA's pipeline operations in Eastern Australia since APA's acquisition of Epic Energy in December 2012. In summary, it identifies likely cost savings from integration of around \$150 million with an additional \$7 million per annum in operating costs.

Three observations should be noted by the Vertigan Examination:

- First, these financial benefits from gas pipeline integration flow directly to APA and under the Code none of the pipeline users share any benefit except at the commercial discretion of APA. APA's user tariffs have not been reduced to reflect the repayment of capital or savings from integration.
- Second, none of the financial benefits identified by the Brattle Group's examination of the integration of APA's transportation network relate to the operation and functioning of a gas market.

Third, the Brattle Report conclusion was that the integration did not increase the "risks" of monopoly price without addressing whether monopoly pricing existed.

