Response to the examination of the current test for the regulation of gas pipelines consultation paper

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DBP Transmission (DBP) is the owner and operator of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), Western Australia’s most important piece of energy infrastructure.

The DBNGP is WA’s key gas transmission pipeline stretching almost 1600 kilometres and linking the gas fields located in the Carnarvon Basin off the Pilbara coast with population centres and industry in the south-west of the State.

DBP Development Group (DDG) is the group of entities that builds, owns and operates new gas transmission pipelines and other associated infrastructure leveraging off the world class pipeline engineering and operating skills of DBP’s management team. Since its inception in 2011, DDG has invested more than $300m in the construction of three new transmission pipelines.

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1. INTRODUCTION

This submission is made by DBP Transmission (DBP) on its own behalf and on behalf of DBP Development Group (DDG).

DBP is the owner and operator of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), Western Australia’s most important piece of energy infrastructure. The DBNGP is WA’s key gas transmission pipeline stretching almost 1600 kilometres and linking the gas fields located in the Carnarvon Basin off the Pilbara coast with population centres and industry in the south-west of the State. Since acquiring the DBNGP in 2004, DBP has expended over $1.8bn in expanding the capacity of the DBNGP, resulting in a 60% expansion in capacity over that time.

DDG is the group of companies that builds owns and operates new gas transmission pipelines and other associated infrastructure leveraging off the world class pipeline engineering and operating skills of DBP’s management team. Since its incorporation in 2011, DDG has already invested approximately $300m in constructing three uncovered, open access gas transmission pipelines in the Pilbara, being:

- The Wheatstone Ashburton West Pipeline, a 123km pipeline which connects the Chevron operated Wheatstone Domestic Gas Processing Plant with the DBNGP. Construction of this pipeline was achieved in February 2015;
- The Fortescue River Gas Pipeline, a 274km pipeline which allows for the delivery of gas from the DBNGP, initially to Fortescue Metals Group’s iron ore operations at the Solomon Hub. Construction of the FRGP was completed in March 2015; and
- The Ashburton Onslow Gas Pipeline, a 30km pipeline which will allow for the delivery of gas from both the Wheatstone gas plant or the DBNGP to generate electricity for the town of Onslow. Construction of this pipeline was completed in June 2016.

In this paper, DBP, on its own behalf and on behalf of DDG, provides a response to the key issues raised in the Examination of the Current Test for the Regulation of Gas Pipelines Consultation Paper released on 4 October 2016 (Consultation Paper).

The main points in this submission are as follows:

- Changes to the coverage criteria in the National Gas Law (NGL) are being considered based solely on findings made by the ACCC in the ACCC East Coast Gas Market Inquiry Report (ACCC Report). Any changes that are decided upon will apply not only to the East Coast jurisdictions but also to Western Australia and therefore will have a direct impact on WA transmission pipelines. Yet, evidence of what has transpired in the WA gas market was not part of the ACCC’s inquiry. A proper examination of the WA gas pipeline and wider gas market in that state demonstrates no change to the coverage criteria is warranted. It demonstrates a well-functioning pipeline capacity market that is appropriately responsive and dynamic to the needs of its upstream and downstream participants.
- In particular, the examination will reveal:
  - There has been significant investment by pipeline owners in the expansion of covered pipelines under arrangements that fall outside of the regulatory framework of the NGL and at tariffs that are in excess of the reference tariff set by regulators – this demonstrates that:
    - well informed shippers do not consider that the reference tariffs reflect the “ceiling” for an efficient price; and
    - most shippers on covered pipelines such as the DBNGP consider that the benefits of negotiated outcomes outweigh the benefits of regulation;
  - Interconnectors have been built over the last 10 years such that all of the State’s transmission pipelines are now interconnected, facilitating diversity of supply choice for all consumers in the State – this demonstrates that pipeline owners and operators such as DBP and DDG have been instrumental in facilitating competition in upstream and downstream markets;
  - Facilities have been constructed to allow for the supply into the domestic market of 6 additional new gas supply sources since 2008 – a 200% increase in the number of suppliers. These facilities have been constructed well in advance of when gas has been made available for supply. This also
demonstrates that pipeline owners and operators such as DBP and DDG have been instrumental in facilitating competition in upstream and downstream markets; and

- There has been significant investment by DDG in the construction of uncovered, open access pipelines over the last 5 years, opening up new gas markets for consumers. Not only has this investment been made at rates of return that are commensurate with prevailing conditions in the market for funds, the infrastructure has been designed with spare capacity to accommodate the reasonably foreseeable growth in demand. This not only demonstrates that there is no monopoly pricing, it also demonstrates that the long term interests of consumers are being served.

- Consideration of the role of transmission pipelines in the WA energy market is even more important in circumstances where:
  
  - 64% of the nation’s gas is produced in WA;
  
  - gas accounts for more than 50% of the total energy consumed in that State;
  
  - 24% of the 86 transmission pipelines in Australian are located in WA;
  
- The gas transportation requirements in Western Australia are currently undergoing significant change with new domestic gas production facilities about to come on line in the north west of the state and resource projects in the Pilbara looking to switch from diesel to lower cost natural gas for their energy needs. Furthermore, the Pilbara region is a significant contributor to the nation’s economic wellbeing. The Pilbara contributes 17.5% of WA’s economic activity and 2.8% of Australia’s economic activity. Gross regional product per capita is more than 6 times the state level and more than 10 times the national level at $690,000 per capita. In light of the above evidence, any change to the regulatory framework that has the potential to adversely impact the incentives to invest in pipelines, particularly in circumstances where there is very little (if any) evidence to warrant such change, should be carefully considered.

- Even if consideration of the situation in Western Australia is not considered relevant, there are a number of problems with the ACCC Report which should be carefully analysed before making a decision as to whether to change the current NGL coverage criteria and if so, what change to make (particularly of the decision is to implement the ACCC’s recommendations in the ACCC Report). They include:

  - the core of the ACCC’s arguments contained in the ACCC Report, that monopolists mid-stream (like gas pipelines) can exert their market power and charge monopoly prices without affecting competition upstream or downstream, is wrong. The ACCC Report does not appear to have analysed the relevant theory of monopolist behaviour which, if it were undertaken, should not have led to the ACCC making the proposed change to the coverage criteria.

  - Furthermore, the evidence which the ACCC has publicly relied on in the ACCC Report about monopoly pricing is scant, and it would appear it has relied on a handful of specific commercial arrangements as evidence of widespread wrongdoing in the industry.

  - The ACCC has not analysed the cost of regulation, currently not borne by consumers on unregulated pipelines, and has likewise missed some of the key impacts regulation is likely to have.

  - There is a significant amount of policy change being proposed to interrelated elements of the regulatory framework for gas pipelines. Not only are these elements interrelated, the changes are being considered by disparate review bodies and under different timetables. Some of these changes are likely to address the very problems the ACCC believes it has found and which the ACCC justifies to recommend changes to the NGL coverage criteria, meaning its proposed changes to the NGL coverage criteria are unnecessary. Other components would, if combined with a change in the coverage criteria (which appear designed to foreshadow regulation of a significantly greater part of the pipeline industry that is presently the case), likely lead to a great deal of investor uncertainty. This suggests that, if there is any case to be made for change (and DBP considers the ACCC has not made it) that it would be prudent to:

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2 Pilbara Regional Council, Supporting Economic Prosperity in Northern Australia via the creation of a Pilbara Special Economic Zone
• Only proceed now to implement changes to the NGL coverage criteria that ensure alignment with the Commonwealth’s proposed changes to the declaration criteria in Part IIIA of the Competition & Consumer Act (CCA)

• Consider the changes to the coverage criteria in parallel with the reviews of the other parts of the NGL that are presently on foot;

• allow other policy changes to be effected first – in particular the implementation of changes to the secondary pipeline capacity trading market arrangements; and

• undertake a more detailed review of the NGL’s coverage criteria once the above changes have had been implemented and their objectives have been given a chance to be realised.

In this regard, DBP refers to the submission of the Australian Gas and Pipelines Association which DBP has been involved in preparing.

The following chapters address DBP’s concerns in relation to these points above, and a concluding table provides DBP’s responses to the particular questions raised in the Consultation Paper; with reference as necessary to the more substantive points raised in the main body of the submission.
2. EFFECTIVENESS OF WESTERN AUSTRALIA’S GAS MARKET HAS NOT BEEN CONSIDERED

DBP notes that to date, the consideration of changes to the NGL’s coverage criteria has been undertaken solely based on findings made by the ACCC in the ACCC Report. Should any changes be made, they will apply to not only the East Coast but also to Western Australia. Yet, the WA gas market was excluded from the inquiry which led to the findings in the ACCC Report.

Any changes to the NGL’s coverage criteria therefore will have a direct impact on WA transmission pipelines. Yet, a proper examination of the WA gas pipeline and wider WA gas market demonstrates no change to the coverage criteria is warranted. It demonstrates that there exists a well-functioning pipeline capacity market that is appropriately responsive and dynamic to the needs of its participants. In particular, the examination will reveal:

- There has been significant investment by pipeline owners in the expansion of covered pipelines under arrangements that fall outside of the regulatory framework of the NGL and at tariffs that are in excess of the reference tariff set by regulators – this demonstrates that:
  - well informed shippers do not consider that the reference tariffs reflect the “ceiling” for an efficient price; and
  - most shippers on covered pipelines such as the DBNGP consider that the benefits of negotiated outcomes outweigh the benefits of regulation;
- Interconnectors have been built over the last 10 years such that all of the State's transmission pipelines are now interconnected, facilitating diversity of supply choice for all consumers in the State – this demonstrates that pipeline owners and operators such as DBP and DDG have been instrumental in facilitating competition in upstream and downstream markets;
- Facilities have been constructed to allow for the supply into the domestic market of 6 additional new gas supply sources since 2008 – a 200% increase in the number of suppliers. These facilities have been constructed well in advance of when gas has been (or in one case will be) made available for supply. This also demonstrates that pipeline owners and operators such as DBP and DDG have been instrumental in facilitating competition in upstream and downstream markets; and
- There has been significant investment by DDG in the construction of uncovered open access pipelines over the last 5 years, opening up new gas markets for consumers. Not only has this investment been made at rates of return that are commensurate with prevailing conditions in the market for funds, the infrastructure has been designed with spare capacity to accommodate the reasonably foreseeable growth in demand. This not only demonstrates that there is no monopoly pricing, it also demonstrates that the long term interests of consumers are being served.

Appendix A: contains a high level overview of the WA gas market that demonstrates:

- There has been a significant increase in gas supply diversity over the last 8 years;
- Pipeline owners and operators such as DBP and DDG have been instrumental in facilitating competition in upstream and downstream markets; and
- Pricing outcomes for shippers are efficient, even in the absence of coverage for pipelines.

Consideration of the role of transmission pipelines in the WA energy market is even more important in circumstances where:

- 64% of the nation's gas is produced in WA;
- gas accounts for more than 50% of the total energy consumed in that State; and
- 21 (24%) of the 86 pipelines in Australian are located in WA;

The gas transportation requirements in Western Australia are currently undergoing significant change with new domestic gas production facilities having, or about to, come on line in the north west of the state and resource projects in the Pilbara looking to switch from diesel to lower cost natural gas for their energy

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3 Devil Creek, Pluto, Gorgon, Wheatstone, Red Gully and Macedon have all commenced production since 2008
needs. Furthermore, the Pilbara region is a significant contributor to the nation’s economic wellbeing. The Pilbara contributes 17.5% of WA’s economic activity and 2.8% of Australia’s economic activity. Gross regional product (GRP) per capita is more than 6 times the state level and more than 10 times the national level at $690,000 per capita.\(^5\) In light of the above evidence, any change to the regulatory framework that has the potential to adversely impact the incentives to invest in pipelines, particularly in circumstances where there is very little (if any) evidence to warrant such change, should be carefully considered.

In addition to the information contained in Appendix A: following are case examples of some of the recent developments in the pipeline market in Western Australia that demonstrate there is no case for change to the NGL coverage criteria in Western Australia.

**Case Study #1 - 2014 DBNGP Expansions and Recontracting – shippers decide efficient tariffs**

The DBNGP has been in private ownership since 1998 when it was sold by the State to Epic Energy. Epic Energy undertook an expansion of the DBNGP, completed in June 2000, that increased firm full haul capacity on the DBNGP to 513 TJ/day through the addition of compressors, a new compressor station (compressor station 10) and duplications of the pipeline on part of the southern portion of the DBNGP.

Since January 2000, the DBNGP has a covered pipeline, initially under the National Third Party Access Code for Natural Gas Transmission Pipelines and its successor, the NGL.

DBP purchased the DBNGP in October 2004. At this time, DBP was owned 60% by DUET Group, 20% by Alcoa and 20% by Alinta Ltd. Alinta Ltd was later subject to a takeover and the DBP ownership was controlled by Babcock and Brown Infrastructure, later Brookfield. This 20% stake was ultimately acquired in 2011 by DUET Group. In April 2016, DUET Group acquired the remaining 20% equity interest held by Alcoa.

A summary of the history of the DBNGP is shown in the timeline below in Figure 1.

**Figure 1: DBNGP timeline**

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\(^5\) Pilbara Regional Council, Supporting Economic Prosperity in Northern Australia via the creation of a Pilbara Special Economic Zone
Since acquiring the DBNGP in 2004, DBP has continued to expand the capacity of the DBNGP in a series of stages, in each case driven by additional, contracted, customer demand:

- **Stage 4 Expansion** - Completed in December 2006, increasing the firm full haul capacity of the DBNGP to approximately 640 TJ/day. This expansion was achieved through the installation of 217km of looped pipe and the addition of eight new compressor units. The total capital cost (including capitalised borrowing costs) of the Stage 4 expansion was $443.1 million and the project was delivered on time and within budget;

- **Stage 5A Expansion** - Completed in November 2008, increasing the firm full haul capacity of the DBNGP to approximately 733 TJ/day. This expansion was achieved through the installation of 571km of looped pipe and the reconfiguration of certain compressors. The total capital cost (including capitalised borrowing costs) of the Stage 5A expansion was $631.1 million and the project was delivered on time and within budget; and

- **Stage 5B Expansion** - Effective completion was announced on 29 April 2010, increasing the firm full haul capacity of the DBNGP to approximately 845 TJ/day. This expansion was achieved through the installation of 440km of looped pipe and the addition of a new compressor unit. The total capital costs (including capitalised borrowing costs) of the Stage 5B expansion was $716 million and the project was delivered on time and within budget.

As a result of the Stage 4, Stage 5A and Stage 5B expansions, the firm, firm full haul capacity of the DBNGP has been increased by more than 300 TJ/day. In addition to increasing Capacity, the looping that has been installed has improved the reliability and reduced the fuel gas costs (as a percentage of gas transported) of transportation of gas along the DBNGP.

Importantly, notwithstanding this pipeline being a covered pipeline, all of the expansions have been funded under gas transportation contracts whose terms and conditions and tariffs sit outside of the regulatory framework of the NGL and its predecessor. These tariffs have always been higher than the reference tariff for the closest reference service to the negotiated contracts.

The three stages of expansion were facilitated by a standard long-term access Standard Shipper Contract (SSC) DBP negotiated in 2004 with all shippers seeking firm full haul capacity (T1 SSC). The T1 SSC was structured with the aim of aligning the interests of both the DBNGP owners and the shippers by delivering a revenue profile, resulting from commercially negotiated tariffs higher than prevailing reference tariff, were is sufficient to underpin the capital cost of expansions.

These circumstances of ongoing expansion of the DBNGP demonstrate that:

- well informed shippers do not consider that the reference tariffs reflect the “ceiling” for an efficient price; and
- most shippers on covered pipelines such as the DBNGP consider that the benefits of negotiated outcomes outweigh the benefits of regulation;

Furthermore, DBP commenced discussions with the SSC shippers in late 2013 by making a presentation to each customer outlining a re-contracting proposal that aimed to demonstrate a potential value proposition for shippers to re-contract with DBP prior to 2016, with value to DBP and to Shippers as follows:

- Certainty for DBP’s revenue stream post-2015;
- Certainty for DBP’s Capacity volumes post-2019;
- Greater certainty for Shippers compared to their potential outcomes from a regulatory reset; and
- A tariff that was at a discount to the then prevailing tariff, which DBP could offer by taking advantage of low interest rates and hedging of post-2015 exposures

On 7 August 2014, DBP announced that the re-contracting had been completed. The effect of the Re-contracting has been as follows:

- >85% of contracted firm Full Haul Capacity (including Alcoa Exempt Contract) attracts a negotiated tariff as opposed to a regulated tariff. The level of the negotiated tariff is higher than the then prevailing reference tariff;
• All T1 SSC Shippers other than one shipper group participated in the recontracting. This shipper group represented ~15% of DBP’s contracted firm full haul capacity, which reverted to the Reference Tariff at the start of 2016;

• Benefits for DBP include:
  • Greater revenue and earnings certainty out until 2020 given that the negotiated tariff is higher than the regulated tariff;
  • <15% of firm Full Haul contracted Capacity being subject to regulatory reset in 2016;
  • Reset of interest rate hedges at historically low interest rates largely offsets reduced revenues in FY15; and
  • Precedent for potential further recontracting in 2020.

Again, this recontracting exercise demonstrates that:
• well informed shippers do not consider that the reference tariffs reflect the “ceiling” for an efficient price;
• most shippers on covered pipelines such as the DBNGP consider that the benefits of negotiated outcomes outweigh the benefits of regulation; and
• DBP’s customers in WA have gone to great lengths to avoid the cost and involvement in regulatory processes.

Case Study #2 - Fortescue River Gas Pipeline – providing new markets with access to gas at efficient tariffs

In January 2014 DDG\(^6\) announced the decision to fund the construction of the Fortescue River Gas Pipeline (FRGP). At an estimated total cost of $178 million, practical completion of the 274km, unregulated, open access pipeline project was achieved in March 2015 and allows for the delivery of gas from the DBNGP, initially to Fortescue Metals Group’s iron ore operations at the Solomon Hub.

**Project Overview**

The foundation gas transportation agreement that supported the initial investment decision was entered into between a subsidiary of Fortescue. A cornerstone of the agreement was that DDG agreed to cap its rate of return at 10.3% on a budgeted capital expenditure for the project. The effect of these arrangements is that DDG agreed to take all the risk on not only the construction costs but also on the rate of return.

The key features of the FRGP are:

- it is an uncovered pipeline for the purpose of the NGL;
- it is a 16-inch diameter pipeline and runs from the DBNGP’s compressor station one (CS1) around 150km south of Karratha through to Fortescue Metal Group’s Solomon Hub, a distance of 274 kilometres. The pipeline supplies natural gas to the 125MW power station which services Fortescue’s mining operations in the region, as shown in Figure 2.
- There is presently a large amount of unused pipeline capacity on the pipeline. DDG is therefore incentivised to grow the level of demand on the pipeline. In this regard, Fortescue has publicly indicated its intention to increase the role gas plays in its operations across the Pilbara, meaning the FRGP is well placed to deliver gas to these operations, through extensions of the existing mainline.

Further detail is outlined in the ASX announcement made 10 January 2014 (Appendix A: ).

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\(^6\) DDG was established in 2011 to build, own, operate and maintain gas transmission pipelines and associated infrastructure complementary to DBNGP. DDG is a wholly owned subsidiary of DUET Group, an ASX-listed energy utility business in Australia.

DDG utilises the resources of DBP, owner and operator of DBNGP under a Support Service Agreement (SSA). Under the agreement, DBP provides services and personnel to DDG to enable it to undertake its business. The SSA ensures that DDG’s capabilities are supported by DBP’s existing policies and systems and leadership of its highly experienced managers and personnel with over 30 years of successful operation of the DBNGP.
Figure 2: DDG’s Pilbara Pipelines

**Competition considerations**

DBP notes that the ACCC Report recognised that the competitive environment at the time of the decision to construct a new pipeline is likely to be effective in limiting market power. Further the Consultation Paper cites the Northern Gas Pipeline and QSN Link as examples relied upon in the ACCC Report to suggest that competition to build a pipeline can impose an effective constraint on the associated pricing in initial primary capacity contracts.

The FRGP is another example of the competitive and efficient outcomes that are delivered at the time of a greenfields pipeline’s investment decision. DDG was selected as the pipeline proponent as a result of an expressions of interest (EOI) process conducted by Fortescue Metals Group. Not only was DDG competing with other pipeline proponents for the construction of the pipeline (along different routes) as part of this EOI process, it proposed a pipeline route that was not the route preferred by Fortescue. Furthermore there was also competition from other energy sources, including an overhead transmission powerline solution from Port Hedland. Furthermore, DDG had to compete with the pre-existing fuel source that was being used to generate on site electricity at Solomon – diesel.

In addition to there being no market power at the time of construction, there is no evidence of DDG possessing exploitable market power post the initial decision to build the FRGP.

Importantly, the construction of the FRGP is a significant step increase in the competition for pipeline service in the Pilbara market. Before commissioning of the FRGP, the Pilbara was serviced by two other pipelines the Goldfields Gas Pipeline (GGP) and the Pilbara Energy Pipeline (PEPL) both of which are owned by the APA Group.

To demonstrate there is no significant market power wielded by the service provider in the market for Pilbara pipeline services, each of the relevant market segments are reviewed as follows:

1. **Access to spare capacity**

The FRGP is heavily underutilised and so, there is no demonstrable marker power held by DDG for the following reasons:

- The sale of spare capacity by DDG would happen in competition with any of FMG’s unutilised contracted capacity that could be traded to third party shippers.
• There is competition from competing fuel sources, particularly from remote diesel power generation, especially in the current low oil price environment.
• Where there is no spare capacity available a third party can seek expansion of the FRGP.

2. Developable capacity

There is also no demonstrable marker power for the provision of developable capacity via the FRGP for the following reasons:

• While there are certain requirements for the operator to work with the foundation shipper, DDG is not prohibited from expanding the FRGP to allow additional capacity services on the FRGP and for those service to be offered to a third party. The pipeline could be expanded by adding compression and further by adding looping;
• There is competition from alternative pipelines in the Pilbara region owned by an alternate service provider.
• In particular, we note that the Economic Regulation Authority of WA (ERA) found, in assessing whether a recent expansion of the Goldfield Gas Pipeline should form part of the covered pipeline, that it was not satisfied it would be uneconomic for anyone to develop another pipeline to provide services by means of the GGP. The direct evidence to support this finding was that the FRGP was under construction showing that the economics of iron ore in the Pilbara are able to support a standalone pipeline;\(^7\);
• Relevant in the instance where the pipeline is underutilised, there is competition from Fortescue who has the right to trade capacity to third parties;
• Again, there is also competition from competing fuel sources, particularly from remote diesel power generation, especially in the current low oil price environment.

The same points are also equally relevant in the development of pipeline extensions if they are so required by third parties.

3. As-available or interruptible services

There is no demonstrable market power for as-available or interruptible pipeline for the following reasons:

• There are currently no services of an interruptible nature provided on the FRGP and given the nature of the markets served by the FRGP, there is unlikely to be any demand for such services in the foreseeable future;
• As the FRGP is currently underutilised, there is direct competition from Fortescue through its ability to trade or on-sell capacity where DDG offers these services;
• Again there is also competition from competing fuel sources, particularly from remote diesel power generation, especially in the current low oil price environment.

\(^7\) ERA Determination 30 May 2014
3. THE ACNC HAS NOT MADE OUT A CASE FOR CHANGE

The previous section of this submission was an attempt to demonstrate that not only has there been no impediment to the development of the WA gas market with the NGL’s current coverage criteria but that:

- access to unregulated pipeline services in WA has been efficient (in an economic sense), therefore maximising the long term economic interests of consumers with respect to price, quality, reliability, safety and security of supply; and
- access to almost all of the capacity on the DBNGP – the largest covered pipeline in WA - has been agreed with shippers on terms and conditions (including as to price) that differ from the terms and conditions for the reference services set for that pipeline. In the case of the tariffs that have been agreed, they are higher than the reference tariff set by the regulator under the NGR.

This is particularly important given that no analysis of the WA market circumstances was undertaken by the ACCC in the ACCC Report but yet the sole reason for considering changes to the coverage criteria that will apply in WA (and the rest of Australia) is the findings and analysis of the ACCC Report itself.

It follows therefore that the current review must consider the evidence of the WA gas market before considering whether any changes should be made to the NGL coverage criteria and if so, what changes should be made.

If, however, it is considered that an assessment of the circumstances in Western Australia are not warranted, then changes to the NGL’s coverage criteria based on the ACCC Report should only be made if the ACCC Report’s recommendations relating to the coverage criteria are based upon a sound understanding of the relevant economic theory and its real-world application.

It is DBP’s submission that this is not the case. In particular, DBP is of the view that the ACCC Report suffers from a number of significant problems which demonstrate that the ACCC has not made out a case for change. They are:

- the core of the ACCC’s arguments contained in the ACCC Report, that monopolists mid-stream (like gas pipelines) can exert their market power and charge monopoly prices without affecting competition upstream or downstream, is wrong. The ACCC Report fails to analyse the relevant theory of monopolist behaviour. Had this analysis been undertaken in the ACCC Report, DBP submits that it should not have led to the ACCC making the proposed change to the coverage criteria.
- Furthermore, the evidence which the ACCC has publicly relied on in the ACCC Report about monopoly pricing is scant, and it would appear it has relied on a handful of specific commercial arrangements as evidence of widespread wrongdoing in the industry. As outlined earlier in this submission, there has been no analysis undertaken of the WA gas market which accounts for over 60% of the nation’s gas that is produced domestically.
- The ACCC’s proposed criteria for coverage would focus on the incorrect issue and most likely lead to all pipelines being covered, which is an inappropriate policy decision.
- Finally, the ACCC has not analysed the cost of regulation, currently not borne by consumers on unregulated pipelines, and has likewise missed some of the key impacts regulation is likely to have.

It is important that these issues be properly considered before considering if any changes should be made to the coverage criteria and if so, what the changes should be. The remainder of this section and section 4 analyse in detail each of these problems and leads DBP to conclude that it would be wrong to implement the changes to the NGL’s coverage criteria that were proposed in the ACCC Report.

Mid-stream monopolists cannot exert their market power and charge monopoly prices without affecting competition upstream or downstream

The ACCC Report, misunderstands the incentives of monopolists and the consequences these have. In particular, the ACCC’s central thesis of monopolists acting to impact efficiency (through monopoly pricing) without any competition effect downstream (or upstream) is simply wrong, except in very narrow
circumstances which do not exist in the gas pipeline industry. The net result is that the ACCC Report, if implemented, would be attempting to address a problem which does not exist and, to make matters worse, in implementing the proposed changes to the coverage criteria, will not only have a significantly adverse impact on investor confidence but will lead to the regulation of a significantly greater part of the pipeline industry than is presently the case because they set the bar for coverage far too low.

The primary problem in the ACCC’s proposed changes to the NGL coverage criteria lies in the fact that it has misunderstood the economic incentives of monopolists and the results these cause. As the Consultation Paper notes:

The ACCC concluded that the current coverage criteria are not designed to address the monopoly pricing observed in the Inquiry that results in economic inefficiencies with little or no effect on the level of competition in dependent markets

The ACCC is wrong in this respect, and a proper understanding of the relevant economic theory and its real-world manifestations show that in fact it ought to have expected an effect on competition in downstream (and upstream – we refer below just to downstream purely to make the narrative easier, but the effect runs both ways) markets if market power is being exercised mid-stream. This means that the existing test is based upon the correct principles, which in turn leads to some fundamentally different policy outcomes compared to those the ACCC contemplates.

Para 3.23 of the Gas Guide sets out the purpose of criterion (a) as it currently stands thus:

The purpose of criterion (a) is to limit coverage to circumstances where it is likely to materially enhance the environment for competition in at least one dependent market. Whether competition will be materially enhanced depends critically on the extent to which the incumbent service provider can and is likely, in the absence of coverage, to use market power to adversely affect competition in a dependent market(s). If the service provider has market power, as well as the ability and incentive to use that power to adversely affect competition in a dependent market, coverage would be likely to improve the environment for competition, offering the prospect of tangible benefits to consumers (including reduced prices and better service provision). (emphasis added)

The key point to note is the difference between incentive and ability. The ACCC is correct insofar as a mid-stream monopolist has an incentive, in fact every incentive, to operate in such a way to maximise its profits without affecting downstream competition. However, it has very little ability to do this effectively. The inability to act in a way which maximises profits without affecting downstream competition forces the mid-stream monopolist that is exercising market power to do so by choosing a single monopoly price (which is not optimal for it) and this gives rise to downstream impacts which should be visible to the ACCC or anyone else interested in competition in that marketplace.

By way of illustration, consider a town with 15 supermarkets that sell only bananas, each serving slightly different customer bases, and served by a single rail link as the town’s only transport link. The train operator is the monopolist, and in a situation like this, monopolists don't just charge one price to all customers unless they absolutely have to. What they do, if they are well informed about their customers and can prevent re-sale, is charge a different price to each customer. This is called price discrimination. That way, they capture (almost) all of the consumer surplus, as well as all of the producer surplus, and this is always better than charging a single monopoly price and capturing only part of the consumer surplus whilst creating a deadweight loss. This is illustrated in Figure 3.

Note that the relevant economic arguments do not depend upon whether there is one monopoly from beginning to end of the supply chain, or whether there is one monopolist (and only one; the situation changes if there are two) at one link in the chain, and perfect competition elsewhere. Take the above example of the town above. If banana production is perfectly competitive and supermarkets in the town are perfectly competitive, then the train operators, if it can get information about the customers of the supermarkets, will charge each supermarket a different price for bananas such that they can extract all of the consumer surplus consumers of bananas would otherwise enjoy; the train operator doesn't need to own supermarkets to get the rents.

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8 Consultation Paper (4 Oct 2016) page 6
Figure 3: How monopolists price

Note – Under perfect competition, the market price is $P_{PC}$ and the quantity is $Q_{PC}$. The perfectly price-discriminating monopolist will produce the same output and sell to the marginal consumer at the same price. Here we have a slightly imperfectly price-discriminating monopolist, represented by the 15 different rectangles. By way of illustration, the monopolist here sells to Supermarket 5 at $P_5$ and sells the quantity $Q_5$ to that supermarket. For Supermarket 15, the price is $P_{15}$ and the quantity $Q_{15}$ which, by construction, is the same as the competitive output and price (though it need not be in a case of slight imperfection like this). As is clear, not quite all of the consumer surplus is captured, as the sum of the areas of the blue rectangles (above $P_{15}=P_{PC}=MC$) is not the same as the area of the red triangle, which is the consumer surplus. However, it is always the case, even with fewer blue rectangles, that the amount of consumer surplus captured is smallest with one price (set at marginal revenue = $MC$, with price $P_M$ and quantity $Q_M$) because the deadweight loss (triangle abc) is largest and because, as a matter of simple geometry, it is impossible to have a single rectangle like $P_{MC}$ which has a larger area than two or more rectangles like the 15 blue rectangles above. The monopolist will thus want to price discriminate to maximise profit.

The way the rail operator would do this is they charge a different price to every consumer, based on their elasticity of demand, with those customers with a high elasticity of demand being charged a high price, and those with a low elasticity of demand being charged a low price. If the ability to price discriminate is “perfect” (that is, not 15 customer groups but every customer individually), the monopolist produces exactly the same output as in perfect competition, and the marginal consumer pays exactly the same price. The only difference between perfect price discrimination and perfect competition is that, under perfect competition, consumers get the consumer surplus, whilst in perfect price discrimination, the monopolist does.

There is thus no argument which can be made on efficiency grounds to differentiate between perfect competition and perfect price discrimination, and thus the ACCC is wrong to suggest that there is an efficiency impact when there is no competition impact. An argument can be made on social justice or equity grounds that consumers, not producers or mid-stream suppliers, should get the consumer surplus, and indeed one might argue that the “long run interests of consumers” demands this. However, the point is moot, because one would only be having this argument if the relevant monopolist could in fact perfectly price discriminate.

The assumptions which permit perfect price discrimination are a perfect understanding of final customer price elasticity and an ability to prevent resale of the goods being sold. Consider first a relaxation of the assumption of perfect information about final consumers, and assume the train operator can differentiate only three, not 15 different customer types in Figure 3. Simple geometry shows that one could still draw the rectangles in Figure 3 in such a way that the right-most one touches the intersection between the demand and supply curve and, were this the case, there would still be the same marginal price and the same output as one would obtain in a competitive marketplace and thus the ACCC would be partially correct; the monopolist would be extracting “rents” (more correctly, consumer surpluses; it would still be earning what economists term “super-normal profits”) and there would be no change in the amount of bananas available for sale, so no effect on competition. However, it would be incorrect to assert that there was an efficiency effect, because the allocative efficiency properties of a market depend upon the
marginal price and marginal value, not the infra-marginal ones. Thus, allowing for imperfect information might have a competition effect as output declines, or it might not; it depends in simple terms on the blue rectangles.

Now consider relaxing the assumption of the monopolist’s ability to prevent resale. Now, Supermarket 15 can make more money from on-selling its bananas to Supermarket 5 (compare \( P_{15} \) with \( P_5 \)), and it will quickly do so. So too will the other supermarkets in the same situation, and the only response the train operator has is to charge a single price to all supermarkets. It will do so such that \( MC=MR \), and this will create a price of \( P_M \) and a quantity sold of \( Q_M \). This is significantly more in the case of price and less in the case of quantity that is obtained under perfect competition and perfect price discrimination. Noting that the supermarkets are competitive, and thus a reduction in the market size of this magnitude (\( Q_{15} \) or \( Q_{PC} \) to \( Q_M \)) will force some of them out of the marketplace. There will thus be a competition effect which should be observable and thus a test like the existing criterion (a) (if not the test exactly as it is, see below) will do precisely what it is intended to do and expose the mid-stream monopolist to the attentions of a regulator.

This is the error the ACCC makes; the mid-stream monopolist has the incentive to act in a way that does not affect downstream competition (though in doing so, efficiency is not compromised; the ACCC is wrong about that), but it only has an ability to do so under very limited circumstances; specifically, when it can effectively prevent resale. Otherwise, the second-best option that the monopolist has will affect the downstream market, and a test focussed on that market will pick up the effect, meaning there is no need to look at the mid-stream monopolist directly.

The key question to ask is whether the gas market is one whereby pipelines can prevent the resale of gas transportation. Clearly, it is not; there are active bilateral trading arrangements in all contracts and furthermore, secondary pipeline capacity trading markets are available in respect of most pipelines, and will be further promoted by related energy market reforms proposed by the AEMC. This will mean that a mid-stream pipeline, acting as a monopolist will not be able to do what it is incentivised to do (price discriminate) but will instead be limited by its inability to price discriminate into a situation where it charges a single monopoly price for transport. As seen above, this will cause an impact downstream, which should be observable and amenable to any test like criterion (a) designed to pick up precisely this kind of effect.

There is no widespread monopolistic pricing in the industry

The ACCC, however, purports to have observed monopoly pricing by pipelines, but without any competition effects downstream; or at least without any such effects which could be actionable via Section 46 of the CCA. Leaving aside the evidence provided by DBP in section 2 to demonstrate that there is no monopoly pricing by DBP or DDG in the WA market, there are two possible explanations for this:

- The ACCC is simply wrong, and it has taken a series of isolated anecdotal examples out of context, missed information about the particular examples which might explain particular prices, and extrapolated inappropriately to the whole industry.
- The effects downstream exist, but the law is too coarse-grained to pick them up which DBP notes is by design to reflect to costs of regulation – there must be material effect in an adjacent market.

Starting with the first possibility, the ACCC itself clearly believes this not to be the case, but it is difficult for third parties to really assess the evidence because so much of it is anecdotal; we see reference to “evidence of prices two to five times regulated rates”\(^{10}\), but this appears to be for as available and interruptible services (and then we are not told how pervasive this is), or evidence of one pipeliner charging 70 percent more than would be the case under regulation\(^{11}\), even though demand was declining.

Moreover, most of the comparison appears to be against regulated rates, not some competitive benchmark. This implicitly assumes that only the regulator is able to determine the efficient price. DBP submits that, at least in the case of the pipelines that it owns and operates, this is an incorrect assumption to make for the following reasons:

\(^{10}\) ACCC ECGI Report page 108
\(^{11}\) Ibid 114
• As outlined in section 2, more than 85% of the contracted firm full haul capacity of the DBNGP has been agreed to with shippers at a tariff that is higher than the reference tariff set by the regulator for the most comparable reference service and on terms and conditions that differ to the reference service terms and conditions. To suggest that most of the shippers were forced to agree to a tariff that is higher than a reference tariff on a covered pipeline in circumstances where all of the shippers’ contracts terms and conditions already provided that the tariff was to revert to the reference tariff from 1 January 2016 and that this higher tariff is inefficient is untenable.

• while the recent merit review applications determined by the Australian Competition Tribunal in respect of east coast network service providers may have determined that most of the AER’s approach to the calculation of the return on equity was not erroneous for the purposes of the NGL, this does not mean that only the rates of return set by the AER are efficient. It simply means that the service providers were not able to demonstrate error of the kind required under the NGL. The Tribunal actually held that differing minds might reasonably hold a wide range of views as to the “right” rate of return or one that would be found in competitive markets.

• The framework of the NGR is such that while service providers might propose efficient prices in their access arrangement submissions, the regulator is afforded such wide discretion under the NGR for most of the building block components of the reference tariff calculation that it can replace the service provider’s efficient pricing proposal if it considers that a preferable alternative exists.\textsuperscript{12}

To make a comparison against more market-oriented data than the ACCC’s Chart 6.1, we consider Figure 4, from a recent Deloittes survey of CFOs, which asked them about hurdle rates.

Figure 4: Hurdle rates for projects in the real world

\begin{figure}[h]
\centering
\includegraphics[width=0.5\textwidth]{chart4.png}
\caption{Hurdle rates used to assess investment and capital expenditure}
\end{figure}

The figure above suggests that roughly three-quarters of projects use hurdle rates (which may include debt and equity; the ACCC considers the return on equity alone, which is generally higher than a combined debt and equity hurdle rate) sit between ten and 16 percent, which is where roughly half of the ACCC’s chosen set of projects lie in its Chart 6.1. It is impossible to draw definitive conclusions, because the ACCC evidence is from 11 incremental projects, and we are not told how large these projects are (only that they fall in a range of $10-120m which is a relatively small range when considering nationally significant infrastructure assets) or how representative each is of investment returns in the industry more generally, and further the Deloittes figures tell us little about relative risk in the market more generally compared to the pipeline sector. However, it does not seem that the gas pipeline sector is particularly far out of kilter with projects more generally.

Perhaps more to the point, the ACCC’s findings drawn from 11 incremental projects and are far from conclusive, precisely because they are for incremental projects. The commercial opportunities and risks service providers when investing in these projects are very different to those applying across the asset as a whole.

\textsuperscript{12} See Rule 40(3) NGR
Incremental projects do not represent a large proportion of the asset base, estimated to be around 5% and where the cost of these projects as reported by the ACCC is from $10-120m are not significant investments when compared to the overall asset base of a transmission pipeline which may be measured in the billions.

It is far from clear that the ACCC has found pervasive evidence of monopoly pricing on the basis of a handful of incremental projects.

The second point is that effects might exist, but the existing law is too coarse-grained to pick them up. For example, output downstream might decline, but the level of competition downstream is such that all of the firms in the industry still remain, or the nature of the downstream service means that a decline in demand is not immediately obvious. The Productivity Commission (2013, p173) notes in the Virgin case that high airside charges would have been unlikely to cause the exit of a competitor or the number of flights being offered.13

If this is the case, then an argument might be made for a change to the coverage criteria, in particular criterion (a), if the output change alluded to in Figure 3 can be demonstrated. However, any such change would be incremental in nature and would, most importantly, not take focus away from the downstream (and upstream) markets, which is what the ACCC’s proposed change to the criteria does.

**ACCC’s proposed criteria has the wrong target**

We now turn to a more detailed discussion of the criteria proposed by the ACCC which, apart from having the wrong target, are worded in such a way as to effectively guarantee coverage for almost the whole pipeline sector. This is clearly not an appropriate policy direction for the gas sector in Australia.

The ACCC proposes a three-pronged test for coverage:

- the pipeline in question has substantial market power
- it is likely that the pipeline will continue to have substantial market power in the medium term
- coverage of the pipeline will or is likely to contribute to the achievement of the National Gas Objective (NGO) (for example, by promoting efficient investment, operation and/or the use of natural gas services for the long-term interests of consumers of natural gas).

The first two components essentially act together and address the same issue, market power. As a test their merits lie in how the test of “substantial market power” is applied. If the test is applied by looking at downstream markets and examining whether the observed market conditions are significantly different from those that would apply if the mid-stream monopolist were pricing at a competitive level, then, as discussed above, this would be an appropriate outcome. However, the same effect could be achieved via relatively minor changes to the existing criteria, which already has this downstream (and upstream) focus and it is unclear why one would wish to make this wholesale change, which is ambiguous about the nature of the test.

If the test is applied in a relatively simplistic way by, for example, simply asking whether the pipeline in question is the only one serving a given market, then this would be the wrong kind of test, with the wrong kinds of outcomes, because it draws the focus away from the effects of any market power and means that any pipeline serving a market alone, regardless of what effects it is having, would be liable for coverage; subject to the third leg of the test. Arguably, most pipelines would fail the test if a simple criteria focussing on something like market share is applied at this stage. Perhaps of more concern, the ACCC quite clearly intends that the focus be on something like the market share of pipeline services in a given region, because of its mistaken view that looking downstream and upstream tells one nothing about the exercise of market power by a mid-stream monopolist. Thus, it seems likely that this wrong version of these two legs of the test would be likely to prevail.

The third leg of the test appears attractive because it invokes the NGO, but it is perhaps the most problematic of the three legs because the ACCC has failed to draw a distinction between something which is good as guide to regulators and what is required when one is trying to assess whether something should be regulated; they are not the same. The proposed limb of the criteria is simply far too subjective and in no way includes any pragmatic test that could be applied by a decision maker.

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13 Here the decrease in output may have been seen in, for example, fewer of those flights leaving full.
In its use of the NGO as the goal for regulation, it is entirely appropriate to expect that regulators consider efficient investment in pipelines, efficient operation of pipelines and the long term interests of consumers with respect to price, quality, safety, reliability and security in the supply of gas. However, this is vague and subjective and at worst, one which may be impossible to argue against. This is most especially the case because imposing coverage requires only that it is ‘likely’ to contribute towards the NGO.

The first two criteria are thus only appropriate if applied correctly and it is not clear the ACCC intends their correct application because of its flawed understanding of the incentives and activities of monopolists with respect to upstream and downstream markets. More to the point, they are ambiguously worded, and one could achieve their correct application by making minor changes to the existing criterion (a) which has the correct focus and is not ambiguous. The third criteria is a ‘Claytons’ criteria which sets the hurdle far too low from coverage being determined. DBP fears that potentially taken together, the sole purpose of the three criteria is to ensure an industry is regulated rather than an appropriate balance be struck between reaping the advantages of a dynamic market able to respond to market signals and the appropriate regulation of natural monopolies where regulation materially promotes competition.
4. THE UNINTENDED CONSEQUENCES OF REGULATION

It is DBP’s submission that in considering what, if any, changes should be made to the NGL coverage criteria, particularly changes which will lead to almost all pipelines being regulated (such as is likely to occur under the ACCC’s proposed changes), one must consider the issue of the cost that regulation has on matters such as investment incentives or the way in which efficient businesses operate.

The ACCC Report does not appear to have considered this issue.

It is DBP’s submission that there are likely to be significant costs and unintended consequences of excessive regulation.

It is instructive in this context to read the Productivity Commission report of 2013 cited by the ACCC, wherein the Commission is far less sanguine about regulation, and gives far more space to documenting how policy has quite deliberately raised the bar to ensure that Australia does not end up with too much infrastructure being regulated. DBP would like to highlight three issues associated with regulation which appear to have been ignored by the ACCC in the ACCC Report:

- The costs imposed when an asset goes from being unregulated to regulated.
- The impacts of regulation on new investment, and how the “access holiday” provision currently available to infrastructure owners may be diluted.
- The impact of regulation on key downstream industries, particularly mining.

Costs of delay in regulatory approvals processes

It is certainly not the case that regulators are able to perfectly capture efficient costs, particularly when one considers the three elements of productive, allocative and dynamic efficiency. A former Commissioner of the ACCC captures this neatly when he observes (PC 2013 p 103):

‘setting the appropriate price requires much detailed, difficult to obtain information about industry cost and demand conditions, making some degree of regulatory error inevitable’

However, even if a heroic assumption is made that regulators get the right answer eventually, the process of making a regulatory decision is a long and costly one. By way of one example, DBP submitted its access arrangement proposal for the 2016 to 2020 access arrangement period (1 January 2016 to 31 December 2020) in December 2014. The Economic Regulation Authority (ERA) made its final decision 18 months later, in June 2016 (six months after the start of the access period). DBP believes the final decision contains several errors in respect of which, DBP has sought merits review under the NGL framework before the Australian Competition Tribunal. The hearing is scheduled for February 2017. If error is confirmed by the Tribunal, the decision will be remitted back to the ERA for reconsideration, meaning that it is likely to be at least June 2017, or 18 months into the access period, before a final price is determined for the remainder of the period. Until that date, shippers with tariffs tied to the reference tariff or prospective reference service shippers have no certainty of the prices which will prevail for the next five years.

This is not an issue which afflicts only Western Australia. Jemena put forward its regulatory proposal for its 2015 to 2020 (July 2015 to June 2020) in June 2014. It obtained a final decision in June 2015, but, believing the AER to be in error on some points, appealed to the Tribunal. The Tribunal heard the complaints in September 2015 and made a decision in February 2016, requiring some elements of the decision be remade by the AER. The AER, however, chose to exercise its rights, and to challenge the Tribunal decision in the Federal Court via judicial review. This case will be heard in October 2016. If the AER prevails, its final decision may be imposed in the first quarter of 2017, but if the Federal Court finds

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14 Regulatory decisions, guidelines and other documents inevitably discuss all three elements of efficiency and assert that said decision/guidelines/document meets all three elements. However, no regulatory decision that DBP is aware of has ever gone beyond examining efficient costs, which covers only productive efficiency. Allocative efficiency is much harder to analyse properly, particularly in light of issues such as the theory of the second best (see https://www.erawa.com.au/wpcontent/2019/2012%20-%20Appendix%20-%20-%20Efficiency%20and%20-%20Theory%20-%20Second%20Best.PDF) and it is unclear if dynamic efficiency can be effectively analysed at all.

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the Tribunal did not err in suggesting the AER made errors, then the AER will need to remake its decision, and Jemena's customers may not have final settled prices until the end of 2017; halfway through its current access period. It would be wrong to suggest that customers, to say nothing of investors facing uncertain revenue streams, do not bear costs from this level of uncertainty.

**Impact on investment incentives for future expenditure**

The costs of delay do not pertain merely to existing assets and access determinations, but more broadly across the sector when new investment is made. Under the NGR, if an expansion in the capacity of a covered pipeline is to occur, the regulator must assess the efficiency of new investment, and has two opportunities to do this: one at the access proposal when the forecast investment is foreshadowed (if indeed it is so foreshadowed) and the other once the subsequent access proposal is submitted and the regulator is asked to approve rolling the expenditure into the regulatory asset base. The risk to investment incentives should the regulator decide, ex ante, to disallow a portion of the capital expenditure being rolled into the capital base after the investment has been made is significant.

While the NGR contains provisions to allow pipeline service providers to seek a binding pre-approval from the regulator of any proposed capital expenditure project as conforming capital expenditure (which, once incurred will be able to be rolled into the capital base)\(^{15}\) - and it is appropriate that the regulatory regime contain these provisions for cases where hundreds of millions of dollars of investment are required to be made - DBP's direct experience with these provisions is that they are incapable of providing investors with regulatory certainty in the timeframe required for an investment decision to be made by the board of directors so as to meet the shippers’ timing requirements for the additional capacity. A summary of DBP’s experience with these provisions is contained in Appendix C:

As a result of the ACCC’s proposed changes to the coverage criteria - which will make it more than likely that all pipelines will be covered – the practical workability of these sorts of mechanisms becomes even more critical to ensure not only that investment incentives are not undermined but that they do not delay, or worse still impede, customers being able to access pipeline capacity in accordance with their timetable.

It is DBP’s submission that the current relevant provisions of the NGR (Rule 80) will not work in practice and therefore pose a significant risk to both the short and long term interests of shippers but also to investment incentives. If any change to the NGR coverage criteria is to be made so as to make it likely that most pipelines will become covered, there needs to also be a changes made to provisions such as Rule 80 of the NGR so as to ensure they are practically workable and do not create costs for the market.

**Removal of market signals**

While the above example provides a pragmatic example of the costs associated with regulation, the more significant ‘cost’ associated with heavy handed regulation (or more specifically price control) are the less tangible opportunity costs such as removing the market signals companies respond to when acting in the market and incentives to innovate and develop new service offerings and allow service providers adopt to a changing market. The ACCC’s Report recognised similar positive characteristics were identifiable on the East Coast\(^ {16}\). It is DBP’s view that these positive traits are also demonstrable in the WA market as outlined in more detail in Section 2.

**New investment and access holidays**

In a situation where a pipeline and a customer both need to invest in a new venture, the pipeline typically has very little market power, because the customer can refuse to invest in the relevant factory, say, unless it gets a good price from the pipeline operator. In this situation, regulation can typically add little to commercial negotiation. In other situations, prior to a pipeline being built, there may be considerable uncertainty about future demand, with upside and downside risk. However, if the pipeline is built and demand eventuates, a regulator, seeing only the upside factual ignores the downside counterfactual faced by investors prior to investment and sets a price that is too low. Investors, considering their next

\(^{15}\) Rule 80, NGR

\(^{16}\) Section 6.1 of the ACCC ECGI Report
investment in a pipeline, and knowing this regulatory asymmetry, do not invest until the downside risk has become clear, which may delay investment from the level which would be optimal.

In recognition of these issues, greenfields pipelines are able to claim 15-year regulatory holidays, provided they can show that the pipeline would not be captured by at least one of the coverage criteria. The ACCC suggests the AEMC will need to consider any interaction a potential new test would have on the 15 year no-coverage provisions. The ACCC suggest that the AEMC will need to consider whether no-coverage determination is provided automatically or new projects are assessed against the market power test, albeit with potential reduced factors.

DBP suggests adopting the latter is problematic. Consider first the first two criteria. They are ambiguously worded, but if they are interpreted in some form of market share manner (see discussion above) then most greenfields pipelines will be captured by these two criteria, because by definition they are usually the first pipelines to a given market.

Consider then the third criteria. As discussed above, the subjectivity of the test makes it difficult to assess a greenfields development against the criteria. In fact, this is doubly difficult for new pipelines, which have very little actual data with which to bolster arguments (about cost or demand), and the whole exercise becomes entirely subjective and hypothetical one.

If the criteria act to make it impossible to avoid regulation or at least significantly ‘lower the hurdle’ for coverage to be granted, then clearly the “access holiday” provision might remain on the statute book, but it would do so with little or no effect, as it seems unlikely that many greenfields pipelines would meet its requirements. Their investment would thus be faced by precisely the regulatory hold-up problem that the provision was designed to avoid.

Lastly, if there is change to the coverage criteria, consideration must be given to the need to grandfather existing pipelines built in the last 15 years which did not seek the holiday because it was never envisaged they would be regulated, otherwise the industry will face sovereign risk issues for future investment next time it decides to change the rules and apply them retrospectively.

**Unintended consequences for the mining sector**

One of the illustrations the ACCC gives intending to highlight the benefits of regulation (p130) is an example of a mining company that, absent of monopoly pricing by an unregulated gas pipeline, would no longer face an investment hold-up problem, and would expand its output of minerals due to lower priced energy. The problem with the ACCC’s example is that it is simply wrong as a point of economics and practical reality, and it highlights an important issue for pipelines such as the DBNGP which serve the minerals industry.

Firstly, in all of the expansions and new pipelines developed by DBP and DDG, the required capacity has been delivered to shippers ahead of the time the shipper required the capacity. DBP and DDG are incentivised to deliver capacity on time to ensure cashflows to service investor requirements.

Mines selling their output into competitive global markets earn resource rents. That is, they have no control over the global market prices (which the ACCC recognises) and thus face an incentive to produce as much as they can, so long as their cost is below the world price. That is, supply does not change if the cost of a producer is one dollar or ten dollars below the global price (the supply curve is vertical, intersecting with a horizontal - from the perspective of an individual firm - demand curve). Thus, if a gas pipeline charges $1 or $10 for gas transport (or access), it will make no difference to the output of the relevant mine, so long as the free on board price of the ore is below the global market price, because the mine in question gets no benefit from withholding any supply just because its energy costs increase; it will either supply or not supply depending upon whether its total costs are below or above the global price. This is the nature of resource rents, which dictate “all or nothing” supply decisions rather than the smoothly upward-sloping supply curve of an elementary economic textbook.

More to the point, the energy company knows this. In fact, if it is well-informed, it can deduce what all of the other costs of the mining company are and, provided it is the only monopolist supplying the mining company (otherwise it shares the resource rents), it will set the energy or access price at a level that

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would not risk the viability of the mine.\textsuperscript{18} In that way it can extract all of the resource rent without taking any of the risks associated with mining. This concept was well-ventilated, in a different context, in the application by FMG to use the transport infrastructure of Rio Tinto and BHP before the National Competition Council (NCC), and should have been considered by the ACCC. It does not appear to have been considered in the ACCC Report.

The contrary point, which the ACCC does not appear to have grasped, is that putting a regulator into the investment decision between a pipeline and one of its shippers, particularly a shipper such as a mining company, and the regulator itself becomes a “hold-up” problem, because the processes necessarily go through in order to understand what the regulatory price ought to be; information the financiers of said pipelines will need before they are willing to provide debt financing. This is not something which can be easily fixed by regulators working more quickly, but rather a fairly fundamental difference between the way commercial negotiation processes work and the way regulators work, as we discuss above in respect of the costs of regulation.

Thus, in the area of gas for mining and minerals processing, the ACCC has presented a benefit from regulation removing monopoly pricing which simply does not exist once one understands resource economics properly, and has ignored a significant issue associated with the clash between regulatory and commercial processes. The major issue we perceive is that the ACCC’s investigation, which did not consider WA, may impose blanket changes on the gas sector nationally, and adversely impact a key sector of Australia’s future export growth in WA.

\textsuperscript{18} Or, as is more usually the case, at a price just a bit lower than the competing fuel of diesel; which is why gassification tends to happen when diesel prices are high, and not when they are low. Additionally, this example ignores the fact that, prior to the gas infrastructure being built, the mining company has a fair amount of bargaining power, particularly if it is the foundation customer for energy infrastructure which will subsequently serve other mines at a lower incremental cost.
5. CONSIDER THE EFFECT OF OTHER REFORMS

The ACCC presents the issue as being a clear market failure which it has uncovered, requiring immediate attention, and which can only be addressed by changing the coverage criteria to facilitate the regulation of gas pipelines. However, quite apart from the flaws in its economic logic, and thus the mistaken proposed replacement criteria, there are a number of other changes occurring within the energy policy space that give the ACCC a greater ability to deal with issues of market power (to the extent that they do in fact exist) without pursuing the option recommended in the ACCC Report.

While it should be noted that several of these changes became apparent only after the publication of the ACCC Report, this current review, looking at the issue six months later and able to see the changes, is able to examine options the ACCC could not. We explore some of these policy changes below.

A related issue is the sheer volume of change going on in the governance and regulation of the sector at the moment, meaning the future overall governance structure is currently unsure. It would appear to be ill-advised to engage in a policy reform which has the potential to so significantly expand the remit of the AER at a time when the overall governance framework is changing so significantly. We discuss this issue, with an example, in the second part of this section. The overall message is that now is not an ideal time for the major change the ACCC proposes, even if they were well-targeted.

Other policy options to explore before regulation

There are, at present, a number of substantial changes proposed for the energy industry in general and gas pipelines in particular. Many of these have at least the potential to achieve what the ACCC hopes to achieve through regulation, at the cost of much less disruption to the industry and its customers. Reviews and other related events currently on foot include:

- The Newcastle Port challenge (discussed previously) which may change how Criterion (a) for declaration is interpreted.
- The changes to Sections 45 and 46 of the Competition and Consumer Act, which may change how the ACCC can itself address abuses of market power.
- The work ongoing under the COAG Energy Council’s Energy Market Reform Package, particularly, how the coverage regime interacts with Limited Merits Review and the pricing provision so of the regulatory framework (Parts 8-12 of the NGR).

The first of these alternate solutions has been discussed already in respect of the Port of Newcastle access case. It may well be the case that, prior to this case, policymakers could say that Criterion (a) of the current coverage criteria could not be met by those seeking declaration in the gas pipeline issue. However, it is not clear that this is still the case, and it is important to allow some time for the full meaning of this recent Federal Court decision to be understood.

Newcastle Port decision

The ACCC has expressed a view that vertically separated infrastructure cannot be captured by Part IIIA, and this is a motivation for changing the criteria so that this infrastructure can be captured. It may have been possible to assert such a viewpoint in the past, when attempts at coverage of such infrastructure had failed, but it is not clear that this is still the case.

The NCC has determined that the Port of Newcastle should be covered under Part IIIA. This is despite the Port of Newcastle being a vertically separated piece of infrastructure similar to gas pipelines. Whilst the ACT’s ruling is currently subject to appeal, the fact that is has ruled this way demonstrates the ACCC’s, and other policy makers’ and gas market participants,’ view of the coverage criteria may be incorrect.

Changes to the CCA

In its report, the ACCC notes that the behaviour of pipeliners charging monopoly prices is perfectly legal under the CCA, and suggests that this is a market failure which the Act was not designed to address. This is one of the rationales the ACCC uses to push for its recommended change to the NGL coverage...
criteria. However, it is no longer clear that this is the case. Since the ACCC report was published, the Federal Government has published its response to the Harper Review, which was ongoing at the time of the ACCC’s own inquiry, and the Government is foreshadowing some quite substantial changes to the CCA which may facilitate the ACCC prosecuting specific abuses of market power, rather than regulating the entire industry.

The changes are highlighted in Figure 5 below. The key change is the first one.\textsuperscript{19} The Harper Review noted that a key problem with the wording of the law as it exists at present is that it focuses on the impact on a competitor; the issue also raised by the ACCC. However, that has now changed to specifically refer to the competitive process itself. Moreover, the test no longer references intent, but effect or likely effect.

**Figure 5: Proposed changes to the CCA – Section 46**

<table>
<thead>
<tr>
<th>New law</th>
<th>Current law</th>
</tr>
</thead>
<tbody>
<tr>
<td>The conduct must have the purpose, effect or likely effect of substantially lessening competition in that or any other market.</td>
<td>The conduct must ‘take advantage’ of market power.</td>
</tr>
<tr>
<td>The conduct must have the purpose, effect or likely effect of substantially lessening competition in that or any other market.</td>
<td>Conduct must be for a specific anti-competitive purpose, relating to damaging an actual or potential competitor.</td>
</tr>
<tr>
<td>There is a general provision only, and no specific prohibition on predatory pricing or other forms of conduct (however described).</td>
<td>Predatory pricing and other forms of conduct are expressly prohibited.</td>
</tr>
<tr>
<td>A person may seek exemption from section 46 via the Commission authorisation process.</td>
<td>Authorisation is not available for section 46.</td>
</tr>
<tr>
<td>Certain pro-competitive and anti-competitive factors must be taken into account when considering a substantial lessening of competition.</td>
<td>‘Substantial lessening of competition’ is not an element of section 46.</td>
</tr>
</tbody>
</table>


The current wording of Criterion (a) of Part IIIA for declaration is:

that access (or increased access) to the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service;

which is proposed (by the same Competition Policy Review Bill 2016 to be replaced by):

that access (or increased access) to the service, on reasonable terms and conditions, following a declaration of the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service

\textsuperscript{19} Note that the actual proposed wording for the test is “A person who has a substantial degree of power in a market must not engage in conduct that has the purpose, or has or is likely to have the effect, of substantially lessening competition in that or any other market”. 
The proposed wording for misuse of market power is considerably more lenient than that for declaration. Although the effect on competition must still be substantial, the misuse of market power need only have the “effect or likely effect” of said substantial impact, which is a lower benchmark. Arguably, the wording of Section 46 has made the task of the ACCC in showing abuses of market power much easier than the task for third parties in seeking declaration/coverage, and the obvious starting point for the ACCC, having found evidence of monopoly pricing (which must, as discussed previously, have a competitive effect, by virtue of the nature of the economic theory governing how monopoly affects linked industries) should be to make use of its new powers under the CCA to prosecute. In the event either that subsequent successful prosecution shows market power abuses to be widespread, or it transpires that the wording of the law does not allow the ACCC to prosecute where it sees downstream effects (for example, if the courts determine that the ACCC must show the number of players in the market decreases or particular services disappear, which the Productivity Commission noted does not always occur), then there may be scope for introducing more widespread regulation. However, to do so now would be to deny the amended CCA an opportunity to act to prevent precisely the kinds of market failures the ACCC professes concerns about, and to develop suitable case law to address similar market failures regardless of where they might occur in the economy. Regulation is thus not costless in this respect.

Continual substantive reform creates uncertainty

Review of the coverage criteria should not be considered in isolation, it is important to consider the appropriateness of all other aspects of the NGL and NEL, including but not limited to the original decision making process. This is particularly important in the current circumstances given the Energy Council’s announcement on 19 August 2016 to commence in excess of 17 reviews by a variety of review bodies relating to various aspects of the NEL and NGL. Each of these regimes is made up of a variety of inter-related parts. Change in one part of the NEL and NGL will therefore have an impact on the remaining parts of each law. As an example, in the case of the NGL, reviews have been announced into the limited merits review regime and the pricing and revenue regime. These parts of the NGL are directly related to the coverage criteria of the NGL. Furthermore, each of these reviews is being undertaken by different bodies. It is even more important therefore that the inter-relationship between changes recommended by each review body are properly considered before any changes are implemented.

By way of an example of one change currently being considered which has particular relevance to any consideration of changing coverage criteria in such a way as to increase the number of pipelines covered, consider the current process examining limited merits review (LMR). LMR is seen by investors, particularly overseas investors, as being a vital component of protecting their interests from sovereign risk associated with regulation.

This was made clear in a recent survey of investors by the Royal Bank of Canada, shown in Figure 6.

Figure 6: Importance of limited merits review for investor confidence

<table>
<thead>
<tr>
<th>2013</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Agree</strong> 33%</td>
<td><strong>Agree</strong> 52%</td>
</tr>
<tr>
<td><strong>Strongly agree</strong> 26%</td>
<td><strong>Strongly agree</strong> 33%</td>
</tr>
<tr>
<td><strong>Disagree</strong> 4%</td>
<td><strong>Disagree</strong> 11%</td>
</tr>
<tr>
<td><strong>Unsure</strong> 39%</td>
<td><strong>Unsure</strong> 30%</td>
</tr>
</tbody>
</table>

Disagree 0%
At present, the COAG Energy Council is considering options in relation to limited merits review, with one of the options being to scrap it entirely and rely solely upon judicial review. The loss of limited merits review is a significant issue for the energy sector in Australia, and a topic about which there has been (and will be) significant debate.

If limited merits review is removed, or even if the system is changed substantially, it would seem imprudent to change the coverage criteria at the same time in such a way as to make much more of the gas pipeline sector susceptible to regulation. In, for the energy industry, a worst case scenario of no limited merits review, the AER would have no effective oversight save through judicial review, with its narrow focus, and the industry (and consumers; consumer groups have also recently challenged AER decisions before the Australian Competition Tribunal) would have almost total reliance on the AER getting the right answers all the time. To add a large number of new pipelines, about which the AER knows comparatively little compared to those pipelines it has regulated for some years, at a time when effective oversight of the AER has been removed by other policy would be a recipe for disaster. Even if limited merits review does not vanish, but only changes, it will be some years, given the current regulatory cycle, before the first challenges under any new regime come before the reconstituted or otherwise changed Australian Competition Tribunal, are heard, and the lessons learned from the operation of the new process. If the scope of regulation is expanded significantly before these changes have a chance of working through, then this is likely to cause major sovereign risk issues, particularly for investors who might otherwise have expected the relevant pipelines not to be regulated at all. Thus, if there is a rationale for more widespread regulation at all (and the ACCC’s case is strikingly weak in this respect), then changes in the limited merits review process currently in progress would suggest that a prudent course would be to wait before expanding the scope of regulation.
<table>
<thead>
<tr>
<th>Question number</th>
<th>Question</th>
<th>Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Do you agree with the ACCC’s finding that the majority of existing transmission pipelines on the east coast have market power and are using this power to engage in monopoly pricing? Why/Why not? Please provide evidence to support your argument.</td>
<td>While DBP may not have all the information to hand to make this assessment in full, it is not convinced by the ‘evidence’ contained in the ACCC’s Inquiry report that the ACCC has demonstrated that the majority of transmission pipelines have are engaging in monopoly pricing. Moreover, there has been no consideration by the ACCC of the evidence in WA which, on close examination, reveals that there is no market power leading to monopoly pricing on covered and uncovered pipelines – see section 2.</td>
</tr>
<tr>
<td>2</td>
<td>Is the ACCC’s characterisation of why monopoly pricing is a problem accurate? Why/why not?</td>
<td>To ensure that coverage is limited to assets where it is most required and where a strong case can be made for improved outcomes from coverage to protect property rights and while improving competition. In this regard, DBP refers to the submission by the Australian Pipelines and Gas Association (APGA), the preparation for which, DBP was involved.</td>
</tr>
<tr>
<td>3</td>
<td>Are there any additional effects of monopoly pricing on gas market participants that the ACCC did not identify?</td>
<td>DBP’s view is that the current coverage test is appropriate. See the APGA submission in this regard.</td>
</tr>
<tr>
<td>4</td>
<td>What do you believe is the objective of the existing coverage test?</td>
<td>Yes it is; the ACCC has provided very limited evidence of anything other than marginal issues associated with monopoly pricing. Moreover, there has been no consideration by the ACCC of the evidence in WA which, on close examination, reveals that there is no market power leading to monopoly pricing on covered and uncovered pipelines – see section 2.</td>
</tr>
<tr>
<td>5</td>
<td>To what extent does the current interpretation of the existing coverage test fulfil the objective?</td>
<td>While DBP submits that the criteria are likely not be met by the vast majority of pipelines, this is because it should not be met. The AER has provided very limited evidence of monopoly pricing, and, since any monopoly pricing mid-stream should have an effect on competition downstream as a matter of simple economics, the most likely interpretation of the ACCC’s findings in respect of downstream competition is that there is very little monopoly pricing. See section 3 for more details.</td>
</tr>
<tr>
<td>6</td>
<td>Is the existing coverage test an effective constraint on pipeline operators’ behaviour? Why/why not?</td>
<td>In DBP’s view, a market failure has not been demonstrated by the ACCC. Further, as a point of economic theory monopoly pricing by definition must have some affect in at least a downstream market. Therefore, where monopoly pricing is occurring and it has a material effect on an up or down stream market the asset is likely and appropriately to be covered by the current coverage test. See section 3 for more details.</td>
</tr>
<tr>
<td>7</td>
<td>Do you agree with the ACCC that the existing coverage criteria, and in particular criterion (a), establishes a hurdle for regulation that is unlikely to be met by the majority of transmission pipelines on the east coast? Why/why not?</td>
<td>Yes, based on the economic theory and the legal precedent set by the current coverage test. See section 3 for more details.</td>
</tr>
<tr>
<td>8</td>
<td>Can the coverage criteria be satisfied in the case of a non-vertically integrated pipeline? Why/why not?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Question</td>
<td>Answer</td>
</tr>
<tr>
<td>---</td>
<td>--------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>10</td>
<td>What is the relationship between the gas pipeline capacity trading reforms and the gas access regime?</td>
<td>The AEMC’s capacity trading reforms will increase competition between spare capacity owner by the pipeline operator and pipeline capacity in the secondary market and competition within the secondary market. See section 5 for more details.</td>
</tr>
<tr>
<td>11</td>
<td>What are the implications of any changes to the LMR regime in the context of this examination?</td>
<td>Detrimental levels of uncertainty for investment in pipeline infrastructure. See section 5 for more details.</td>
</tr>
<tr>
<td>12</td>
<td>Absent this examination and any decision by Energy Ministers, once implemented, the amendments to the declaration criteria will see the coverage criteria differ from the CCA. Should the coverage criteria continue to be consistent with the declaration criteria or is an industry-specific test warranted? Why/why not?</td>
<td>It is DBP’s strong preference that there is consistency between regimes. DBP refers to the submissions by the APGA in this regard.</td>
</tr>
<tr>
<td>13</td>
<td>What impact, if any, is the amendment to section 46 of the CCA likely to have on pipeline operators who operate in a manner consistent with that identified by the ACCC as engaging in monopoly pricing?</td>
<td>This amendment to the CCA gives the ACCC the tools it needs to address the monopoly pricing it believes it has found, and obviates the need to regulate. At the very least, the move to lowering the hurdle for regulation should wait until the ACCC has made use of its expanded powers under the CCA. See section 5 for more details.</td>
</tr>
<tr>
<td>14</td>
<td>Is a new regulatory test required under the NGL? Why/why not?</td>
<td>It is DBP’s view that a new test is not required for the reasons outlined in this submission.</td>
</tr>
<tr>
<td>15</td>
<td>What percentage of the price of delivered gas do transportation costs (transmission and distribution) represent?</td>
<td>In WA, less than 5% of the delivered cost of energy to a residential customer relates to transmission pipeline costs.</td>
</tr>
<tr>
<td>16</td>
<td>What impact would a change to the coverage test have on pipeline investment, including capital-raising, debt servicing and innovation?</td>
<td>The change would be significant, because the proposed test significantly lowers the hurdle to regulation. The same is true for proposed regulatory holidays for greenfields pipelines, which will find it much harder to meet the test. This proposed change, imposed upon an industry that was privatised in good faith under markedly different conditions, is likely to have a significant impact the ability to continue to service debt and reduce the incentives to innovate as discussed above.</td>
</tr>
<tr>
<td>17</td>
<td>What impact would a change to the coverage test have on investment, including equity and debt-raising, in upstream and downstream industries/companies?</td>
<td>Pipeline customers will be equally affected. They may receive some short-term gains from low regulated prices, but the ACCC cannot force pipeline investment, and if pipeliners don’t invest, their customers ultimately suffer. With the importance of the Pilbara region on Australia’s economic success, it is even more important to not make any change that creates a risk that investment in this part of Australia is not put at risk.</td>
</tr>
<tr>
<td>18</td>
<td>In relation to the market power test proposed by the ACCC:</td>
<td></td>
</tr>
<tr>
<td>18(a)</td>
<td>Is it likely to address the problem identified? Why/why not?</td>
<td>In the limited sense that it will prevent monopoly pricing, then yes it will work, because if every pipeline is regulated then by definition, none can earn monopoly rents. However, there are other far more appropriate means to address the problems the ACCC identifies (even if they are real, which should be questioned) that are far less heavy-handed. See section 3 for more details.</td>
</tr>
<tr>
<td>18(b)</td>
<td>Is it likely to better facilitate the achievement of the NGO? Why/why not?</td>
<td>No – because inserting the NGO into the coverage test itself is far too subjective and requires not pragmatic test for coverage. Significantly lowering the bar to regulation fails to</td>
</tr>
</tbody>
</table>

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adequately recognize the true costs of over regulating an industry. The costs will be felt by way of the loss of the market innovation and dynamism that has been demonstrated in the pipeline industry across Australia.

See section 3 for more details.

| 18(c) | Would the test increase the number of pipelines regulated? Why/why not? | Yes, it is very likely to increases the number of pipelines regulated. The ACCC has not considered the cost of regulation – see section 4 for more details. |
| 18(d) | Would the test likely see the prices charged by pipeline operators move towards the efficient cost of supply? Why/why not? | It may see prices go down, but that does not necessarily mean a move towards efficiency, and certainly not towards efficient prices that are in the long term interest of consumers. In WA, evidence indicates that negotiated tariffs which are higher than the regulated tariffs are efficient, given the level of take up by shippers. See section 2 for more details. |
| 18(e) | Are the outcomes associated with pipeline prices moving towards the efficient cost of supply appropriate? Why/why not? | |
| 18(f) | Should the proposed test be implemented, what impact, including costs, benefits and risks, would you expect this to have on market participants? | Pipelines would stop investing, certainly until the ramifications of a widely regulated industry are worked out, and would then start investing to respond to the incentives regulation provides, not to proper market signals. Policymakers should look much more carefully at the extent and type of investment that has occurred over the past decade, and should not kid themselves that regulation will not distort the investment signals that would otherwise be given by a functioning market. |
| 18(g) | If implemented, should the proposed test also apply to 15 year no-coverage determinations? | No, in fact policymakers need to go grandfather existing pipelines built in the last 15 years which did not seek the holiday because it was never envisaged they would be regulated before the ACCC proposed its new test. |
| 18(h) | Are there any unintended consequences of the test? | Yes, see points above. |
| 19 | Is there a regulatory test that would be more appropriate than that proposed by the ACCC? If so, please provide details of what form this test could take. | DBP’s view is there has not been a case made for change. To the extent change is required it should be to adopt changes that have already been accepted by the Government under the Harper review to promote consistency between regimes. |
APPENDIX A: WA GAS MARKET OVERVIEW

The WA gas market was excluded from the ACCC’s inquiry. In DBP’s view, an examination of the WA gas pipeline and wider gas market demonstrates that it is a well-functioning market that is appropriately responsive and dynamic to the needs of its participants. The following provides a brief overview of the WA pipeline infrastructure, developments and increased level of integration and diversity that has evolved since the creation of the coverage criteria.

WA Pipelines

WA has an integrated pipeline system that enables gas to be transported from gas production facilities in the Carnarvon Basin/North West Shelf and the Perth Basin to gas customers throughout the state. The main gas transport pipelines in WA are the DBNGP, the Parmelia Pipeline, the GGP, the Pilbara Pipeline System, the Midwest Pipeline and the Telfer Pipeline, each of which is depicted below.

The WA pipeline system is not connected to the pipeline systems in the Northern Territory or the east coast of Australia.

In addition to the DBNGP, and the DDG owned Wheatstone and Fortescue River Gas Pipelines, there are five other pipelines in WA:

DBNGP

The DBNGP is essential infrastructure for WA and is the only pipeline connecting the significant gas reserves of the Carnarvon Basin on WA's North West Shelf with mining, industrial, commercial and residential customers in the south west of WA (which includes Perth and surrounding regions). The pipeline runs a distance of 1,530 km from the Burrup Peninsula, near Dampier in the north of WA, to Bunbury in the south west of WA.

The DBNGP was constructed by the State Energy Commission of WA (SECWA) and commissioned for operation to Kwinana Junction in 1984 and then to Bunbury in 1985 in a series of expansions to meet growing demand. Capacity of the DBNGP has increased from an initial Capacity of 200 TJ/day in 1985 to the current average firm Full Haul Capacity of the pipeline of 845 TJ/day. The DBNGP was privatised in 1998 and acquired by DBP in 2004. It is currently regulated by the Economic Regulation Authority (ERA) of WA under the terms of the National Gas Access (Western Australia) Act 2009 (which incorporates the NGR).

Parmelia Pipeline

The Parmelia Pipeline was commissioned in 1971 and transports gas from the Dongara gas processing facilities in the Perth Basin to customers in the Perth metropolitan area and the south west of WA. In addition, gas is transported from the north west of WA and delivered into the Parmelia Pipeline via an interconnection with the DBNGP at Mondarra, 12 km south of Dongara. The Parmelia Pipeline is owned by APA Group.

The Parmelia Pipeline is a 356mm (14") diameter pipeline, which runs for approximately 420 km from Dongara to Pinjarra with an additional 31 km in eleven laterals. It is currently capable of delivering up to 70 TJ/day.
Goldfields Gas Pipeline (GGP)

The GGP was commissioned in 1996 and transports gas from the Carnarvon Basin gas processing facilities to the gas users along the pipeline route ending in the Kalgoorlie area in the south of WA. The GGP begins at Yarraloola, which is located adjacent to compressor station 1 on the DBNGP (140km south west of Dampier). The GGP is connected directly to the Varanus Island facilities through a trunk line and also receives gas from the Karratha Gas Plant via an interconnecting pipeline that links the GGP with the DBNGP. The GGP is approximately 14" in diameter and is approximately 1,378km in total length excluding laterals. The GGP has capacity to deliver approximately 200 TJ/day. The mainline of the GGP and the Newman Lateral of the GGP are currently owned by APA Group (88.2%) and Alinta Energy Limited (11.8%). Excluding the Newman Lateral, the lateral pipelines are 100% owned by APA Group. There are two lateral pipelines at the end of the GGP that service loads of 20 TJ/day and 6 TJ/day.

In 2013, APA expanded the GGP on the back of a 15-year gas transportation agreement with Mount Newman JV (85% owned by BHP) and a 20 year Rio Tinto transmission contract. The expansion increased capacity by 28% (44 TJ of additional capacity) with reported capital expenditure of approximately $150 million.

While the GGP is a covered pipeline for the purposes of the NGL, the ERA made a determination that the expansion does not form part of the covered pipeline\(^\text{20}\).

Pilbara Pipeline System

The Pilbara Pipeline System (PPS) was commissioned in 1996 and comprises the Pilbara Energy Pipeline (PEPL), the Burrup Extension Pipeline (BEP), the Karratha Lateral and the Wodgina Lateral pipeline. The PPS is owned by APA Group. The PEPL is an 18" diameter, 219km pipeline running north east from the Karratha gas processing facility to Boodarie, near Port Hedland. The BEP is a 24km pipeline connecting the PEPL at Karratha to the Karratha Gas Plant. It runs parallel to the DBNGP until main line valve seven located approximately 20km south of Dampier. DBP has entered into a lease arrangement with APA Group for the BEP and its associated plant, equipment and installations, as well as part of the BEP capacity. This lease of the capacity of the BEP is used by DBP in lieu of building additional looping of the DBNGP mainline. This was accepted by the ERA has an efficient use of pipeline capacity given the BEP was, at the time, significantly under utilised.

The Wodgina Lateral is an 80km pipeline connecting the PEPL to a tantalum mine at Wodgina and the Karratha Lateral is a 5km pipeline connecting to the Horizon Power Karratha Power Station.

Telfer Gas Pipeline

Connected to the PEPL is the Telfer Gas Pipeline, which runs for approximately 443km east from Port Hedland to Telfer. The Telfer Gas Pipeline has a capacity of approximately 25 TJ/day. The gas for the Telfer Gas Pipeline is sourced from Carnarvon Basin suppliers and is owned by Marubeni (49.9%), Osaka Gas (30.2%) and APA Group (19.9%). The Telfer Gas Pipeline delivers gas to the Telfer gold mine, owned by Newcrest Mining Limited.

Midwest Pipeline

The Midwest Pipeline was commissioned in 1999 and transports gas from an interconnection with the DBNGP near Geraldton to Windimurra and Mt Magnet in central WA. The Midwest Pipeline is 353km long, has a diameter of 203/178mm and is able to transport approximately 20 TJ/day of gas. Gas transported on the Midwest Pipeline is sourced from the Carnarvon Basin via the interconnection with the DBNGP. Horizon Power (a WA state government owned entity) and APA Group each own 50% of the Midwest Pipeline.

Fortescue River Gas Pipeline

The Fortescue River Gas Pipeline (FRGP) reached practical completion in March 2015 at total cost of $178 million. The project was announced in January 2014 by DBP Development Group (DDG) along with the formation of an unincorporated joint venture named the Fortescue River Gas Pipeline JV (The Joint Venture) with TEC Pilbara Pty Ltd (a 100% owned subsidiary of TransAlta Corporation).

The FRGP is a 16-inch diameter pipeline and runs from the DBNGP’s compressor station one (CS1) around 150km south of Karratha through to Fortescue Metal Group’s (FMG) Solomon Hub, a distance of

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\(^{20}\) ERA Determination notice
270 kilometres. The pipeline supplies natural gas to the 125MW onsite power station at Solomon which services Fortescue’s mining operations in the region. A more detailed description of the FRGP is provided in Appendix B.

**WA Gas Supply**

There are over 48 gas producing fields located in the Carnarvon Basin, which the WA Department of Mines and Petroleum has estimated to contain gas reserves and resources of 95,914 PJ, with a further 37,815 PJ in the nearby Browse Basin. There are currently five operating gas processing facilities for the Carnarvon Basin gas fields, two of which are located on Varanus Island, approximately 100km west of Dampier, the Karratha Gas Plant which is located on the Burrup Peninsula, approximately 10km north east of Dampier, the Devil Creek gas plant, approximately 45km south-west of Dampier and the Macedon gas plant at Ashburton North, approximately 210km south-west of Dampier.

The Varanus Island gas processing facilities supply gas to approximately 30% of the WA gas market. The Harriet Gas Plant is operated on behalf of the Harriet Joint Venture, comprising Quadrant Energy and Kufpec Australia Pty Ltd. The East Spar Gas Plant is operated by Quadrant Energy. This plant processes gas on behalf of each of the East Spar Joint Venture, the John Brookes Joint Venture (each comprised of Quadrant Energy and Santos BOL Ltd) and the joint venture partners independently. The Varanus Island facilities have direct connections to the DBNGP and the Goldfields Gas Pipeline (“GGP”) at Yarraloola, approximately 140km south west of Dampier.

The Karratha Gas Plant located on the Burrup Peninsula is owned by the NWS Domestic Gas JV and operated by Woodside Energy Limited. This facility processes gas for two NWSG joint ventures, being the NWS domestic Gas JV and a later joint venture comprising of the NWS Domestic Gas JV and Japan Australia LNG (MIMI) Pty Ltd. The Karratha Gas Plant can supply up to 630 TJ/day of gas to the domestic market, which represents approximately 45% of WA production capacity. Gas produced at the Karratha Gas Plant is transported to customers through the DBNGP via a direct connection to the DBNGP at Dampier, at the upstream end of the DBNGP. The Karratha facility also processes gas into LNG to be exported to customers in Japan, South Korea and China.

Quadrant Energy is the operator of the Devil Creek gas plant and the Reindeer gas field. The Devil Creek gas project is a joint venture comprised of Quadrant Energy (55%) and Santos BOL Ltd (45%) dedicated to supplying the WA domestic gas market. The Devil Creek Gas Plant commenced operations in December 2011 and currently has a processing capacity of 220TJ/day.

BHP Billiton Petroleum commissioned the Macedon Gas Development in September 2012. The Macedon Gas Plant delivers gas into the DBNGP through an 87km on-shore pipeline owned by the Macedon JV Partners and operated by the BHP Billiton Petroleum. BHP Billiton Petroleum is Operator of the Macedon Project and has a 71.43% interest, with joint venture partner Apache Northwest which has a 28.57% interest.

The Macedon project involves four offshore production wells supplying a wet gas pipeline to an onshore gas treatment plant at Ashburton North, 17 kilometres south west of Onslow. The domestic gas plant has a design capacity of 200TJ/day.

**Continued significant investment**

Continuing significant investment in the upstream sector in WA will result in two additional gas supplies commencing domestic production for supply into the DBNGP over the next two years, in addition to the five current suppliers. Interconnection with the DBNGP to enable these suppliers – the Chevron operated Gorgon and Wheatstone projects - to deliver gas into the DBNGP has already been completed. Gorgon is anticipated to start domestic supplies in Q3 2016 and Wheatstone in 2017.

Existing supplies come from the Woodside operated North West Shelf Joint Venture, the Quadrant Energy operated Varanus Island plant (Harriet Joint Venture), the Quadrant Energy operated Devil Creek Gas Plant and BHP’s Macedon Project.

Additionally, a small production facility operated by Empire Oil & Gas in the Perth Basin north of Perth (called Red Gully) began producing into the DBNGP in 2013.

As of 1 July 2016 the NWSG venture has moved from joint selling to the marketing of gas as individual Joint Venture partners into the domestic gas market. This has seen gas actively sold by the various
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The move to individual marketing has also opened up the choice of gas suppliers in the domestic market. DBP anticipates by the end of 2017 there will be 30 sources of gas supplier (at seven physical inlets).

Further to this, Woodside’s Pluto Project (which is physically adjacent to the North West Shelf JV) is connected to the DBNGP but does not produce domestic gas into the WA market.

Exploration in the Perth Basin, approximately 400km north of Perth could lead to further gas production from 2020 that is in close proximity to the DBNGP.

**Pluto Gas Project**

The Pluto gas project is located on the Burrup Peninsula, 10kms north-west of Karratha and was commissioned in early 2012. The Pluto project is owned by Woodside (90%), Tokyo Gas (5%) and Kansai Gas (5%) and is operated by Woodside. Forecast production capacity from the single LNG processing train is 4.3Mtpa.

The JV partners have an agreement with the WA Government which stipulates that the plant will supply gas to the domestic market within 5 years of first shipment (being May 2017) though it is expected that this will be achieved through an offsetting agreement with an existing domestic processing facility (such as Karratha). There is already in place an interconnection with the DBNGP to not only facilitate this domgas obligation but also to allow for gas to flow from the DBNGP to the plant to assist in commissioning and maintenance periods.

**Gorgon Gas Project**

On September 14, 2009, Chevron announced that the Gorgon gas project would proceed to development. Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas and Chubu Electric Power are constructing a 3 train, 15.6 Mtpa LNG gas production facility for export, as well as a domestic gas processing facility, located on Barrow Island, approximately 110km west of Dampier in the Indian Ocean.

The facility came online in March 2016 though was shut down in April 2016 for unscheduled maintenance. It is expected that Gorgon will market 150 TJ/d into the domestic market from late 2016 and 300 TJ/d when the project has fully ramped up in 2020.

**Wheatstone LNG Project**

The Wheatstone LNG plant is under construction at Ashburton North, approximately 12kms west of Onslow on the Pilbara coast of Western Australia. In December 2011 the final investment decision was made and construction of the project began. The downstream scope of the project includes two 4.45 Mtpa LNG trains and offtplots and a 200TJ/day domestic gas plant. The LNG plant will be supplied from the Wheatstone, Iago, Julimar and Brunello offshore gas fields. First domestic gas is anticipated to flow in 2018.

In September 2013 DDG reached agreement with Chevron Australia to build, own and operate the domestic gas pipeline that will link the Wheatstone domestic gas plant to the DBNGP, which was commissioned in December 2014 at a capital cost of around A$100 million.

**Other Projects**

The Scarborough gas field is under consideration by BHP Billiton and ExxonMobil for an LNG development that would produce approximately 9,401 PJ of gas.

The Equus gas field is currently being explored by Hess Corporation who has signed a non-binding letter of intent with the NWS JV partners to use the Karratha processing plant. The project is subject to the state gas policy and Hess is expected to reach an investment decision by the end of 2017. Wood Mackenzie expects the project to commence production in 2023.

**Perth Basin**

The Perth Basin supplies gas to approximately 5% of the WA gas market. According to the Independent Market Operator, the Perth Basin currently has proved and probable conventional gas reserves of 35 PJ, which is 0.04% of P2 gas reserves in WA. The gas from the Perth Basin has traditionally been
transported via the Parmelia Pipeline to the Perth metropolitan area, the Kwinana industrial area and to Pinjarra, south of Perth.

In June 2012 Empire Oil & Gas’ Red Gully gas plant, located approximately 140km north east of Perth was connected to the DBNGP. Red Gully can deliver up to 10TJ/day into the market.

A number of small exploration companies are currently exploring the Perth Basin for non-conventional gas, particularly “tight gas” (which is gas locked in relatively impermeable rock formations, shale gas and coal for underground gasification.

Other Gas Supply Sources
WA has three other known areas with proven hydrocarbon producing potential, the first being the Browse Basin, located off the north coast of WA, approximately 450 km north west of Broome.

In September 2013, the Browse Joint Venture participants (Woodside, Shell, BP, Japan Australia LNG and PetroChina) selected floating liquefied natural gas (FLNG) as the preferred development concept for the Browse resources, marking the start of the Basis of Design (BOD) phase.

Woodside (Operator) completed basis of design (BOD) as well as key pre-front-end engineering and design (FEED) work for the proposed development in June 2015 and on 22 March 2016 the JV partners decided not to progress further with the floating LNG development concept.

The JV partners are now preparing a new work program to assess a range of alternatives Inpex has commenced development of an offshore pipeline and LNG plant in Darwin to process gas from its Ichthys field in the Browse Basin. Shell has announced plans to develop the Prelude field adjacent to Ichthys via a floating LNG facility.

The second known area is the Bonaparte Basin, located in WA waters in the Bonaparte Gulf between WA and the Northern Territory. Due to its proximity to the Northern Territory, all gas produced from the Bonaparte Basin is currently delivered into that market, with none delivered into WA. Gas from this area is not expected to be supplied into the DBNGP.

The third potential source of gas is the Canning Basin (near Broome) which is being explored for possible unconventional gas resource in the next few years. The onshore Canning Basin is located in the Kimberley region of WA. The basin is considered 'frontier' in terms of exploration and development to date, in part due to its geographic isolation. Whilst there is currently very limited hydrocarbon production, the Canning Basin has been gaining increasing attention in recent years as having significant potential for unconventional gas resources i.e. 'tight' or 'shale' gas. The EIA puts an estimate of over 300,000 PJ (270 tcf) of unconventional gas resources in WA. Interest in the basin's potential has been highlighted by US major ConocoPhillips taking a farm-in option on a large piece of unconventional gas prospect acreage held by a junior exploration company.

It is considered that commercial gas reserves discovered in the Canning Basin would be most readily monetised by the development of a new gas transmission pipeline connecting the region to the Pilbara Energy Pipeline at Port Hedland some 550km to the south. This in turn would enable access to the DBNGP and thereby access to the major centres of domestic gas demand in the south west of the state.

Future gas produced from the Canning Basin is likely to remain a small fraction in comparison with foreseeable volumes from the offshore Carnarvon Basin. Due to its geographic location Canning Basin gas production does not represent a by-pass threat to DBNGP and is considered to have a positive impact on future DBNGP throughput.

Figure 7 below summarises the increase in gas supply diversity that has occurred over the last ten years.
Figure 7: Increasing gas supply diversity

<table>
<thead>
<tr>
<th></th>
<th>Capacity TJ/d</th>
<th>Operator</th>
<th>Start-up</th>
<th>Reserves life est. years ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>NWS</td>
<td>Woodside</td>
<td>1984</td>
<td>13.4</td>
</tr>
<tr>
<td>2.</td>
<td>Varanus Island</td>
<td>Apache</td>
<td>1986</td>
<td>11.3</td>
</tr>
<tr>
<td>3.</td>
<td>Devil Creek</td>
<td>Apache</td>
<td>2011</td>
<td>12.4</td>
</tr>
<tr>
<td>4.</td>
<td>Macedon</td>
<td>BHP</td>
<td>2013</td>
<td>8.0</td>
</tr>
<tr>
<td>5.</td>
<td>Gorgon</td>
<td>Chevron</td>
<td>2016</td>
<td>40-60 ²</td>
</tr>
<tr>
<td>6.</td>
<td>Wheatstone</td>
<td>Chevron</td>
<td>2017</td>
<td>30+ ³</td>
</tr>
<tr>
<td>7.</td>
<td>Red Gully 1</td>
<td>Empire</td>
<td>2013</td>
<td>2.9</td>
</tr>
<tr>
<td>8.</td>
<td>Senecio/Waitsia</td>
<td>AWW</td>
<td>2019+</td>
<td>10+</td>
</tr>
</tbody>
</table>

Sources:
3) Initial GTA term of 30 years http://www.duet.net.au/getattachment/ASX-releases/2013/Gas-Pipeline-Project
APPENDIX B: FRGP ASX ANNOUNCEMENT 2014

DBP Development Group and TransAlta sign pipeline deal with Fortescue Metals Group

DBP Development Group (DDG), 100% owned by DUET Group (ASX: DUE), is pleased to announce it has formed an unincorporated joint venture with TEC Pilbara Pty Ltd (a 100% owned subsidiary of TransAlta Corporation) (TSX: TA; NYSE: TAC). The joint venture is to be called the Fortescue River Gas Pipeline JV. Its first project will be to build, own and operate a natural gas pipeline from the Dampier Burbury Natural Gas Pipeline (DBNGP) to Fortescue Metal Group’s (ASX: FMG, Fortescue) Solomon Hub operations in Western Australia’s Pilbara region.

The 16 inch diameter pipeline – which will be called the Fortescue River Gas Pipeline - will run from the DBNGP’s compressor station one (CS1) around 150km south of Karratha through to Solomon Hub, a distance of 270 kilometres. The pipeline will supply natural gas to the 125MW TransAlta power station which services Fortescue’s mining operations in the region.

- The project has an estimated total cost of $178 million.
- The Fortescue River Gas Pipeline will be the longest gas pipeline built in Western Australia during the past 10 years.
- A Fortescue subsidiary, FMG Pilbara Pty Ltd, will be the foundation shipper on the pipeline under a 20-year, 100% take-or-pay gas transportation contract with the Joint Venture.

The Joint Venture (in which a DDG company - DDG FR Pty Ltd - will have a 57% interest and TransAlta the remaining 43%) combines the natural gas pipeline expertise of DDG with TransAlta's experience of providing reliable power to remote operations in Western Australia.

DBP Chief Executive Officer Mr. Stuart Johnston said the project would see up to 200 new local jobs created during construction, including involvement from local indigenous communities and over 70% of the project costs spent in Australia.

"Construction is scheduled to commence in July 2014 with completion around the end of the year," Mr. Johnston said, adding “we're hopeful that there will be opportunities for further expansion of the pipeline to other locations in the Pilbara.”
“We are particularly delighted with this news as it comes following our recent announcement of DDG’s appointment to build, own and operate the domestic gas pipeline for the Chevron-operated Wheatstone project.

“DBP has an outstanding reputation as a safe and reliable developer, owner and operator of critical pipeline infrastructure in Western Australia, and we look forward to ensuring the standards we set are continued on this important project.”

ENDS

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About DBP Development Group:
DDG is 100% owned by DUET Group. DDG will be the owner and operator of the Ashburton West Pipeline which, when construction is complete, will connect an existing gas pipeline system to the LBNGP. DDG was established in 2011 to develop, own and operate gas pipelines and associated infrastructure.

About Fortescue:
Fortescue Metals Group is the world’s fourth largest producer of iron ore and a top 20 ASX-listed company. Since its formation 10 years ago, Fortescue has developed five mines and constructed world class port and rail facilities in the Pilbara region of Western Australia. The recent completion of the 40 million tonne per annum Kings mine at the Solomon Hub will lift Fortescue’s sustainable production capacity to 155mtpa by March 2014. By unlocking the potential of the Pilbara, Fortescue is playing an important role in supporting China’s urbanisation and industrialisation. Fortescue shipped its first cargo of iron ore to Baosteel, one of China’s largest steelmakers, in 2008. It has since exported more than 290 million tonnes of iron ore, including 11 million tonnes for third parties, to customers in China and South East Asia.

About TransAlta:
TransAlta is a power generation and wholesale marketing company focused on creating long-term shareholder value. TransAlta maintains a low-to-moderate risk profile by operating a highly contracted portfolio of assets in Canada, the United States and Australia. TransAlta’s focus is to efficiently operate geothermal, wind, hydro, natural gas and coal facilities in order to provide customers with a reliable, low-cost source of power. For over 100 years, TransAlta has been a responsible operator and a proud contributor to the communities in which it works and lives. TransAlta has been selected by Sustainability as one of Canada’s Top 50 Socially Responsible Companies since 2009 and is recognized globally for its leadership on sustainability and corporate responsibility standards by FTSE4Good
APPENDIX C: CASE EXAMPLE – COST OF REGULATION – STAGE 5 EXPANSION

In February 2006, DBP submitted to the ERA a request for agreement under section 8.21 of the predecessor to the NGR (the Code), which was almost identical in terms to Rule 80 of the NGR, in respect of a pipeline expansion – referred to as Stage 5 – which would provide an additional full haul T1 capacity of 310 TJ/d, and which was expected to require investment of some $1.5 billion. Were the ERA to have agreed to the request, it would have agreed, in advance of the investment being made, that the forecast new facilities investment for Stage 5 would meet the requirements of conforming capital expenditure and could be added to the capital base for subsequent recovery via the reference tariff.

The application was made at this time because DBP needed to make an investment decision in relation to Stage 5 expansion by August 2006. While the process under the law did not mandate a timetable that the regulator had to adhere to, DBP’s preliminary discussions with the regulator indicated that the process needed to be commenced by February at the latest in order to allow the regulator to make a decision by August.

This created an immediate set of problems:

- Firstly, negotiations with prospective shippers were ongoing and no shipper had signed a gas transportation contract for additional capacity at that time.

- Secondly, the detailed design of the expansion had not been completed, given that negotiations with shippers were ongoing.

Notwithstanding these limitations, on 27 April 2006, following completion of the public consultation process required under the Code, the ERA issued a Draft Decision on DBP’s request. In the Draft Decision the ERA advised that it proposed to agree that the forecast new facilities investment for the Stage 5 would meet the requirements of section 8.16(a).

However, in its response to the Draft Decision, DBP informed the ERA that some shippers and prospective shippers had been unable to give the commitments that DBP required before investing in pipeline expansion, and that the scale of the expansion project had been reduced to 265 T/J/d of full haul T1 capacity. This required DBP to reconfigure its required design of expansions, thereby impacting on the forecast expenditure for the project.

Subsequently and relevantly, before the final decision by the regulator, other shippers progressively advised DBP that necessary project approvals would not be forthcoming as expected, and that, in the short term, they would be unable to enter into long term gas transportation contracts. Their capacity requirements remained, but they were deferred. By the end of June 2006, DBP could rely on commitments for only 91 TJ/d of the initially anticipated 310TJ/d of full haul T1 capacity, and 86 TJ/d of part haul capacity, required during the second half of 2007, and during 2008.

As a result, DBP had to make further modifications to its design, schedule and budget for the expansion project. Importantly, while DBP considered that ultimately, the overall demand would materialise, it would not be able to be the subject of a single investment decision. Instead, a three staged expansion program was planned. These commitments became the basis of proposals for the first such stage - Stage 5A expansion - of the capacity of the DBNGP.
During this process, the ERA was kept informed of the changes in capacity requirements. During June, the ERA advised that the requirement for additional pipeline capacity was so different from the additional capacity DBP was proposing to provide in February 2006 that it could not proceed to a final decision on the February request for agreement under section 8.21. If DBP still required a degree of regulatory certainty, it would have to submit a new request for agreement.

Were DBP to now submit, in respect of Stage 5A, a new request for agreement under section 8.21 of the Code, the ERA would initiate a further public consultation process, and there would be no ability to make a final decision on that request before the time DBP’s board needed to make an investment decision to meet the shippers’ delivery timetable. Were Stage 5A to be delayed until the ERA’s final decision, DBP would be unable to provide the capacity required by the time it is obliged to provide that capacity under the terms and conditions of its Standard Shipper Contracts.

In these circumstances, DBP formally withdrew DBP’s February 2006 request for the ERA’s agreement under section 8.21.

While DBP continued to work with ERA staff on methods for demonstrating that the new facilities investment in Stage 5A would meet the requirements of conforming capital expenditure, it was unable to obtain any binding commitment from the ERA that would satisfy the requirements of its debt financiers.