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Commission

Inquiry into the east coast gas market

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Australian Competition and Consumer Commission
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Commission

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13 April 2016

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Dear Minister

Inquiry into the Competitiveness of the Wholesale Gas Industry

I am pleased to present to you the ACCC's report following its inquiry into the competitiveness of the wholesale gas industry (the Inquiry). The Inquiry follows the notice given to the ACCC to hold an inquiry into the competitiveness of wholesale gas prices and structure of the upstream, processing, transportation, storage and marketing segments of the east coast gas industry pursuant to subsection 95H(1) of the *Competition and Consumer Act 2010 (CCA)*.

Through the course of the Inquiry the ACCC has used the powers available in Part VIIA of the CCA to compel documents and information and hold hearings with industry participants. This has included the receipt of in excess of 73 000 documents and the holding of 32 public and private hearings and numerous additional discussions and consultations.

There has been unprecedented change in the east coast gas market over the last four years, with the development of liquefied natural gas facilities in Queensland. The changes have created winners and losers, and increased uncertainty in the market. Participating in the market has become increasingly complex for many participants, with commercial and industrial customers in particular having been acutely affected by the transition.

There are three key factors feeding into the uncertainty about future gas supply on the east coast:

- The magnitude of gas flows to the liquefied natural gas projects, which are removing gas from the domestic market.
- The low oil price, which is resulting in declining investment in gas exploration and lower production forecasts for both domestic and LNG projects.
- Moratoria and regulatory restrictions, which are affecting onshore gas exploration and development.

Some suppliers have taken advantage of supply uncertainty to increase prices, shorten contract terms and implement more restrictive non-price terms and conditions. More supply and increased diversity of supply will be important for the future competitiveness of the gas market. While the Inquiry acknowledges that there are understandable reasons for policy positions like moratoria, blanket moratoria and regulatory uncertainty act to curtail gas exploration and new production. Projects and activities should instead be reviewed on a case-by-case basis.

While the pipeline sector is responding to the changing dynamics and offering new services, some pipeline operators are engaging in monopoly pricing. The regulatory regime is not fit for purpose for the gas pipeline sector and pipeline pricing is significantly unconstrained. A new test is proposed.

The east coast gas market remains opaque. Confidential bilateral negotiations remain the norm for both gas supply and transportation contracts. The lack of consistent, publicly available data on the sector is an impediment to participants, investors and policy makers.

Risk management has become more challenging, in part because producers are not willing to offer as much flexibility as they once did, and facilitated trading markets have limited liquidity. Trading markets are developing and the Australian Energy Market Commission (AEMC) is working towards further improvements in market design.

As I have outlined, all sections of the gas industry are facing significant challenges. New gas supply and more efficient gas markets will be equally important for enhancing the competitiveness of the east coast gas market in the long term.

Through the course of the Inquiry the ACCC has maintained close contact with relevant Commonwealth and state and territory stakeholders, including the Minister for Resources, Energy and Northern Australia, the Department of Industry, Innovation and Science, the AEMC and the Australian Energy Regulator.

Pursuant to subsection 95P(3) of the CCA, the ACCC is required to release this report after 28 days from delivery to you, unless you direct otherwise.

Yours sincerely



Rod Sims
Chairman

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Executive summary

The development and construction of the three liquefied natural gas (LNG) projects in Queensland, starting in late 2010, triggered unprecedented changes in the east coast gas market.¹

In the period from about 2012 to the end of 2014, domestic industrial gas users started to approach the market seeking new gas supply agreements (GSAs) in anticipation of many large, long-term GSAs coming to an end. Many industrial users reported that they either could not get offers for gas supply during this period for 2016 and beyond or received few offers at high prices with less flexible terms and conditions, including shorter contract durations.

Suppliers and their peak bodies, by contrast, were stating publicly that the gas market was functioning well and that plenty of GSAs were being executed. These conflicting claims about the availability of offers for gas supply and the competitiveness of the east coast gas market formed part of the genesis of this Inquiry.

The Inquiry used the Australian Competition and Consumer Commission's (ACCC) information gathering powers under Part VIIA of the *Competition and Consumer Act 2010* (CCA) to investigate the conflicting claims of industrial users and suppliers. The Inquiry found that many industrial users did experience real difficulties during this period and that they were receiving few, if any, real offers for gas. The offers that they did receive were often at sharply higher prices and on strict 'take it or leave it' terms.

Domestic suppliers were either unwilling or unable to make firm offers for gas supply for 2016 and onwards. They were either already fully contracted, reviewing their supply arrangements and strategies, in negotiation to secure their own supplies or, in the case of the LNG projects, focussed on ensuring gas supply for LNG production rather than supplying additional gas for domestic users. This combination of factors led to great uncertainty for industrial gas users in the domestic market.

There are now more gas supply offers available in the market, but they are from fewer sources of supply, higher priced, often for shorter durations and with tighter non-price terms and conditions. Other problems also remain in the market.

The development of the LNG plants caused major structural changes and market disruption, creating winners and losers

Australia has benefitted and will continue to benefit economically from the three large LNG projects in Queensland. These projects are boosting GDP and employment, and providing a particular benefit to the Queensland economy, especially in some rural and regional areas. However, the dramatic change in the supply-demand balance and new contractual arrangements for conventional gas to support the LNG projects have led to market disruption.

East coast gas demand is expected to soar from around 700 PJ per annum in 2014 to around 1750–2200 PJ per annum in 2017–18 due to exports from the LNG projects. LNG projects are supplementing supply from their own coal seam gas (CSG) reserves by contracting gas from conventional reserves which previously served the domestic market, particularly from the Cooper Basin.

East coast gas prices have historically been low by international standards, but recent price increases are likely to erode this competitive advantage. The new market dynamics and the transitional phase of the gas market had a particularly negative effect on some industrial users. The effects on industrial users vary depending on the alternatives available to them, the extent of their trade exposure, and their use of gas for feedstock or energy or both. Many users have few or no alternatives to gas available to them. Gas can be 15 per cent to 40 per cent of input costs

¹ The 'east coast gas market' is a phrase that has been adopted for the purpose of this Inquiry to describe a geographic area that includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania. It is not an economic or legal definition of any market for CCA purposes.

for some gas intensive industries and up to 80 per cent of costs for some chemical production. Margin reductions for industrial users can typically range from 0.6 to 6.0 percentage points depending on their industry and the level of gas price increases.² The uncertainty around gas availability and pricing resulted in some industrial users deferring investments, choosing shorter-term GSAs or reducing gas usage.

Wholesale gas costs make up 15 per cent to 30 per cent of total residential gas bills³ depending on the state. For example, household bills could increase by 5 per cent in New South Wales and 11 per cent in Victoria if wholesale gas prices rose by \$2/GJ.⁴

The east coast gas market is now also more directly exposed to international oil and LNG prices via LNG export contracts, the LNG spot market and some recent domestic contracts with explicit oil-linked pricing. This has translated into higher and more volatile domestic gas prices. International oil and LNG prices have fallen from very high levels up until mid-2014, to the recent much lower prices. International oil and LNG price changes such as these have been, and will continue to be, a factor affecting prices in the east coast gas market.

In response to the changed dynamics of the east coast gas market, the Inquiry recommends:

- reconsidering the approach being taken under regulatory regimes for gas development in order to alleviate the impact of the three major factors affecting supply
- addressing pipeline sector problems that exacerbate gas supply and pricing issues in the domestic market
- improving market operations and increasing the level of market transparency.

These issues are addressed in turn.

1. Three major factors are affecting supply

While it is clear that there are sufficient east coast reserves to meet likely demand for the foreseeable future, it is not at all clear whether these reserves will be developed in a timely fashion to meet demand at any particular point in time.

There are three key factors feeding into the uncertainty about future gas supply on the east coast:

- Gas flows to the LNG projects, which are removing gas from the domestic market.
- The low oil price, which is resulting in declining investment in gas exploration and lower production forecasts for both domestic and LNG projects.
- Moratoria and regulatory restrictions which are affecting onshore gas exploration and development, in New South Wales, Victoria, Tasmania and potentially the Northern Territory.

The participation of the LNG projects in the domestic gas market has changed market flows

The LNG projects that previously supplied the Queensland domestic market have stopped offering significant additional firm supplies to domestic users to concentrate on ensuring a smooth build-up to LNG production. Some LNG projects are also supplementing self-supply by contracting gas from reserves which previously served the domestic market, particularly from the Cooper Basin. These changes have caused disruption to the market's previous gas flows and have resulted in changed supply dynamics, particularly in the southern states. If the LNG projects seek to maximise production capacity of their LNG trains, gas will continue to flow to Queensland.

² Assuming a starting wholesale price of \$6.00/GJ and a \$2.00–4.00/GJ gas price increase.

³ Oakley Greenwood, *Gas Price Trends Review*, December 2015.

⁴ Assuming baseline wholesale gas prices of \$5.30/GJ in Victoria and \$7.30/GJ in New South Wales estimated by Oakley Greenwood (*Gas Price Trends Review*, December 2015).

The domestic gas market is now more exposed to international oil prices

Another major factor affecting the supply outlook for gas in the east coast gas market is the increased exposure to oil prices. The LNG projects are linking the east coast gas market to the international LNG market, which is linked to oil prices. This linkage has affected expectations around future domestic gas prices. As oil prices fall, the expected returns from production and reserves fall, balance sheets suffer and the level of exploration and development declines. In addition, numerous upstream producers rely on profits from oil production to fund exploration and development and to maintain healthy balance sheets.

The real average price of oil in the post OPEC period is about US\$55/barrel.⁵ This long-term average is punctuated by great swings in the price of oil. For example, the price of oil as at 1 April 2016 was about US\$40 per barrel after averaging above US\$100 per barrel for most of the period from 2011 to 2014. This has left the east coast gas market caught in a clash of cycles where rising domestic gas prices are coinciding with oil prices that remain low after a steep fall. This is driving uncertainty about future supply due to declining spending on exploration and development. Investment funding has also declined, as capital markets become increasingly concerned by the risk profile of the upstream sector of the industry, including for projects which seek to supply the domestic market.

Regulatory restrictions will affect future supply

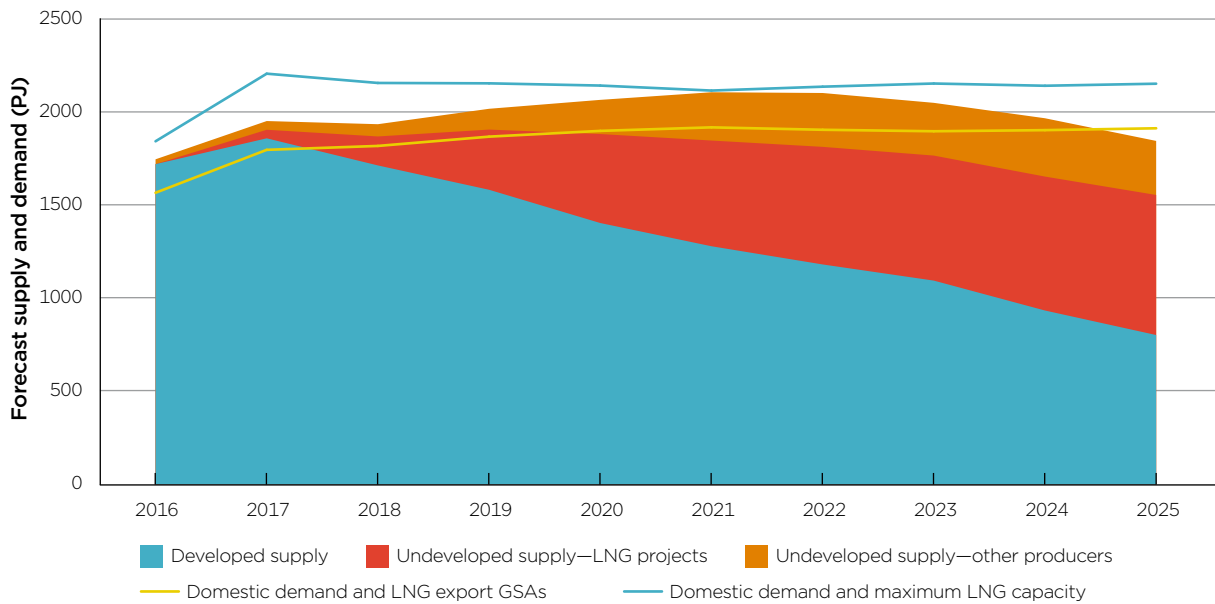
Policy decisions made by governments and regulators affect the level and diversity of supply in the east coast gas market. In particular, there are moratoria and other regulatory restrictions in New South Wales, Victoria and Tasmania preventing or impeding onshore gas exploration and development, and consideration is being given to a moratorium on fracking in the Northern Territory. The Inquiry recognises the important environmental and social considerations underpinning these policy decisions. The Inquiry recommends that proposals for gas exploration and development should, however, be reviewed on a case-by-case basis. These reviews should take account of a range of considerations including the costs and benefits to the domestic gas market, and to industrial users in particular, as well as environmental and social concerns. The greater the level and diversity of supply, located close to demand centres, the more dynamic and competitive the east coast gas market will be.

The supply outlook in the east coast gas market remains uncertain to 2025 and beyond

Sufficient gas production is currently forecast in the east coast gas market to meet domestic demand and existing LNG export commitments until at least 2025, even without gas from the Arrow project (chart 1). However, it is important to note that this requires the development of reserves in projects that are currently undeveloped. There remains uncertainty over the current viability of some of these developments, particularly due to low oil prices.

⁵ 1970–2014 average, 2014 dollars.

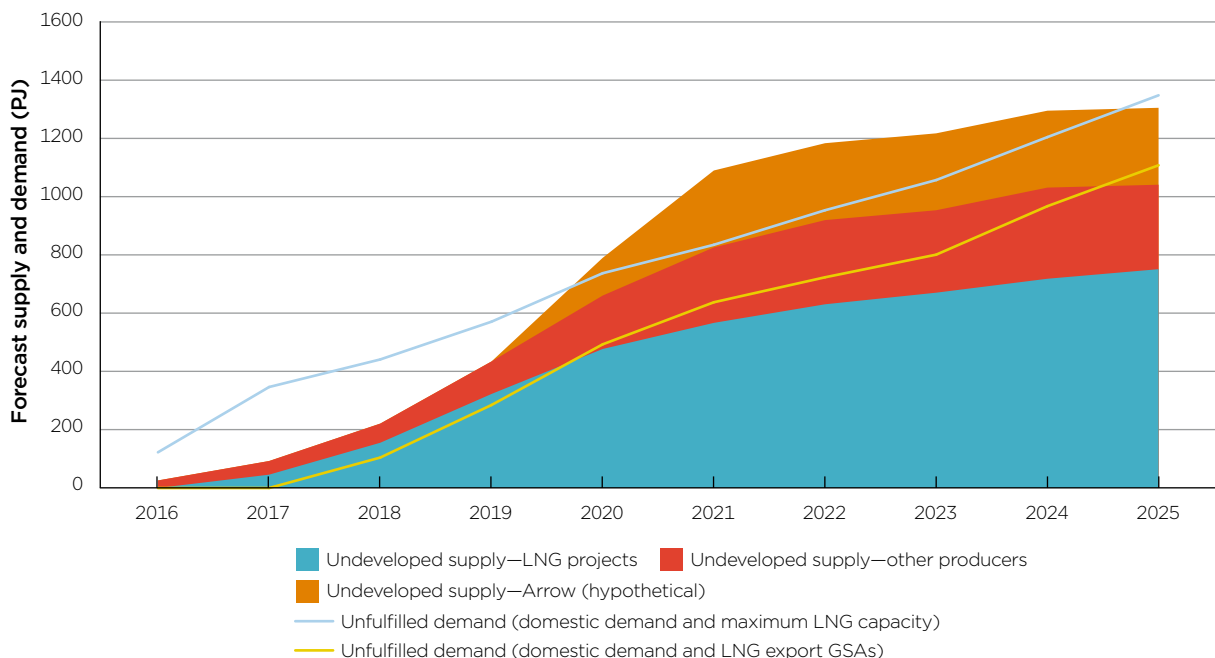
Chart 1: Forecast gas supply and demand balance in the east coast gas market, excluding Arrow, 2016–25



Source: ACCC analysis based on data obtained during the Inquiry, AEMO's 2015 National Gas Forecasting Report and EnergyQuest, EnergyQuarterly, March 2016.

Without further and extensive investment in currently undeveloped gas reserves, there may be significant unfulfilled demand on the east coast (chart 2). Except in relation to Arrow's gas reserves, the production forecasts shown in chart 2 below reflect specific projects. The relevant gas suppliers currently expect to meet these forecasts via those projects. Additional development would be required to produce enough gas to fully use the production capacity of the LNG trains.

Chart 2: Unfulfilled demand and forecast of production from identified undeveloped projects, 2016–25



Source: Data obtained by the ACCC during the Inquiry, EnergyQuest, EnergyQuarterly, March 2016 and AEMO's 2015 National Gas Forecasting Report.

Notes: Undeveloped production forecast for the LNG projects and other producers is based on the same data as in chart 1. 'Undeveloped—Arrow (hypothetical)' is a hypothetical estimate based on public sources.

There are significant commercial uncertainties associated with the timing of the development of currently undeveloped reserves. In particular, a large proportion of future production in the market is expected to come from unconventional CSG fields in Queensland, which are primarily being developed by the LNG projects. The need for continual reinvestment in CSG infrastructure

creates ongoing commercial and technical uncertainty over the exact timing and volume of future gas from these unconventional reserves.

Adding to uncertainty in the supply outlook is a lack of clear information about the likely timing and size of the development of the Arrow reserves. The Arrow Joint Venture holds the most significant uncommitted gas reserves on the east coast. Chart 2 shows a hypothetical development path for Arrow's gas based on publicly available information, but the Inquiry is not aware of any specific business plan to develop Arrow's gas.

There is little prospect of a significant increase in supply from the existing production basins in the southern states.⁶ Some producers in the Cooper Basin and off-shore Victoria have ramped-up production to meet new supply commitments and this may accelerate the decline in their conventional reserves over the medium term. Production costs for existing conventional reserves are increasing as the gas which is easier to extract is used. Development of replacement reserves is currently lagging and may not be available soon enough. Traditional sources of supply, such as the Cooper, Otway and Gippsland basins, face increasing costs and challenging decisions about potential new field expansions in the current economic conditions. In the absence of timely additional investment, there is potential for a significant reduction in supply from traditional sources in the southern states.

In November 2015, the Northern Territory government announced that it had selected Jemena to construct a pipeline (the Northern Gas Pipeline, NGP) to connect the Northern Territory with the east coast gas market for the first time. While volumes supplied over this pipeline are likely to be relatively modest at first, Jemena has stated that the pipeline will be scalable. There are potentially very large shale gas resources in the Northern Territory, which will have a better chance of being commercially developed once they are connected to a large demand source. It is unclear what the ultimate size of these resources might be, or over what time horizon they might be extracted, but the Northern Territory represents a potential large source of supply for the east coast gas market, provided that development of the shale gas resources is not prevented by potential future regulatory restrictions.

Different pricing dynamics apply in Queensland and the southern states

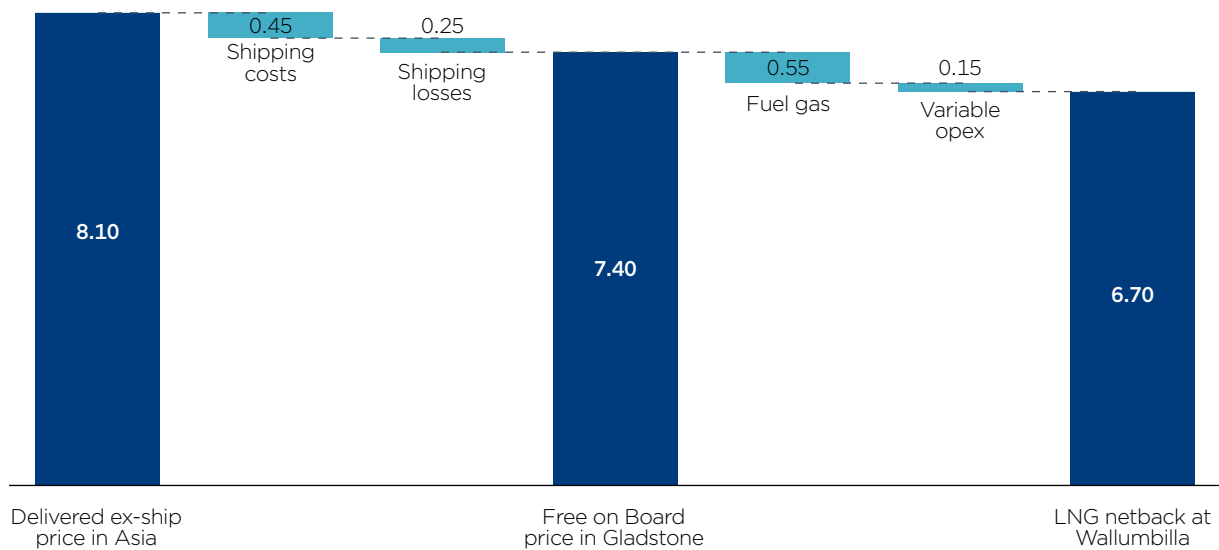
The commissioning of the LNG projects has influenced the pricing dynamics in Queensland and the southern states in different ways. Prices in Queensland are now expected to be shaped by the LNG project fundamentals, while prices in the southern states are likely to also depend on the availability and diversity of supply in those states.

In Queensland, future prices are expected to be shaped by LNG netback prices. The three LNG projects are forecast to have enough gas to meet their contractual commitments in the short- to medium- term. They may, however, require further gas to fully utilise their LNG facilities or cover any unexpected shortfalls in meeting their contractual export commitments. While this continues, domestic users will compete with LNG projects for gas, and domestic gas prices in Queensland will be shaped by LNG netback prices.

LNG netback price at Wallumbilla is calculated by taking the relevant LNG export price in Asia and subtracting the short-run costs associated with shipping and liquefaction (chart 3). This calculation does not make any allowances for recovery of fixed costs or invested capital, which are sunk costs and are not typically taken into account in short-term commercial decisions.

⁶ Southern states include Victoria, New South Wales, South Australia, Tasmania and the Australian Capital Territory.

Chart 3: Illustrative short-run LNG netback pricing example



Notes: Numbers are in \$/GJ. The illustrative, rounded figures in this chart are based on the same LNG netback calculations in box 2.3 in chapter 2.

Prices in the southern states are also likely to be influenced by LNG netback prices, but the cost of transporting gas to, or from, Wallumbilla has created a range of potential pricing outcomes (the shaded region in chart 4).

If there are sufficient supply alternatives available for domestic gas buyers in the southern states, competition will drive suppliers in the southern states to offer a gas price closer to their next best sales alternative. If this alternative is to sell gas to the LNG projects in Queensland, the price that suppliers would receive is the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla and the processing costs at Moomba⁷ (**the seller alternative**).

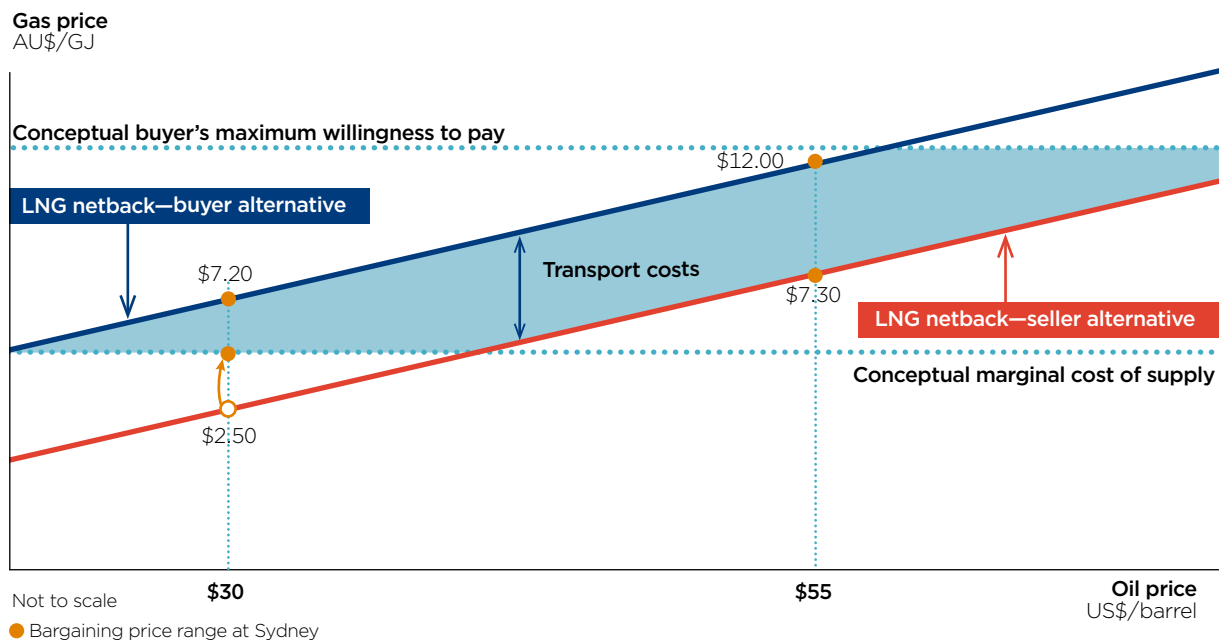
On the other hand, if there are few supply alternatives available to a gas buyer, then producers can charge a price approaching the buyer's next best alternative. If this alternative is to buy gas produced in Queensland, the price that a gas buyer would have to pay for this gas is the LNG netback price at Wallumbilla plus transport costs from Wallumbilla to the buyer's location (**the buyer alternative**).

The significant gap between the buyer and seller alternatives (capped at the buyer's maximum willingness to pay and with a floor of the marginal cost of supply) represents the range of possible pricing outcomes in gas supply negotiations in the southern states. The prices at each end of this range are unlikely to be realised in practice for a number of reasons, including because the gas market is unlikely to be perfectly competitive or fully monopolistic, the negotiating parties do not have perfect information about the state of the market and they may have different expectations about the current and future market conditions. Also, the buyer's willingness to pay will vary by buyer, the marginal cost of supply will vary by supplier and both will vary through time. Nevertheless, there is still a considerable range of possible pricing outcomes. Where the domestic gas prices will ultimately end up is likely to depend on availability and diversity of gas supply in the southern states.

To illustrate the importance of the gas price range, at an oil price of US\$55/barrel, which is around the real average price of oil in the post OPEC period, a gas price of \$7.30/GJ may see most industrial gas users stay in production while a gas price of \$12/GJ may not (see chart 4).

⁷ Processing is required to ensure the gas meets the required specification for the LNG projects.

Chart 4: Bargaining framework for gas supply negotiations in Sydney



Note: The gap between the buyer and seller alternatives consists of two components—the cost to the buyer of transporting gas from Wallumbilla to their location plus the cost to the seller of transporting gas from the buyer's location to Wallumbilla including processing at Moomba and gas losses.

The floor is the supplier's marginal cost of supply and the ceiling is the buyer's maximum willingness to pay. The buyer's maximum willingness to pay and the marginal cost of supply in this chart are purely illustrative.

In this illustrative example, the seller alternative price at an oil price of \$30/barrel is below the marginal cost of supply, so the marginal cost of supply would set the floor for bargaining.

The illustrative prices in this example assume oil prices, percentage conversion rates and a fixed exchange rate. These assumptions do not hold for wider ranges of oil prices. Sydney was chosen as an illustrative location.

Declining production in the Otway and Bass basins, redirection of gas from the Cooper Basin to Queensland, moratoria and other regulatory restrictions on on-shore gas exploration and development in New South Wales, Victoria and Tasmania have combined to severely reduce the availability and diversity of supply in the southern states. This means that domestic users in the south are becoming highly reliant on gas produced by the Gippsland Basin Joint Venture (GBJV).⁸

In these circumstances, there is unlikely to be sufficient competition in the south to constrain the GBJV from charging a price approaching the buyer alternative. This means that to increase competition and put downward pressure on prices, changes are needed to encourage increased supply and a larger number of suppliers to the domestic market, particularly in the south. Increased competition could potentially result in southern gas users paying up to \$4/GJ less for their gas, by moving the price negotiation outcome closer to the seller alternative than the buyer alternative. However, the extent of potential gains is affected by the factors mentioned earlier and could be limited further if new gas supply has a high cost of production or is located far from the key southern demand centres.

Gas reservation policies should not be introduced

Gas reservation policies seek to shield domestic users from the effects of linking to export markets. They include policies to require a percentage share of gas reserves or production to be placed in the domestic market, or export controls which require a licence for exporting gas subject to certain conditions, such as a national interest test, which could include considerations of the impact on domestic supply.

In the short term, such policies may reduce prices for domestic users as additional gas is forced onto the domestic market above efficient market demand. These artificially reduced prices weaken the economic incentives for further gas exploration and appraisal. In addition, new gas

⁸ The Inquiry notes that AGL recently reached an agreement with Cooper Energy to buy up to 53 PJ of gas from Sole project over eight years and up to 4 PJs per annum from the Manta project. This could result in new alternative gas supply coming out of the Gippsland Basin, although this is a relatively small volume of gas.

projects which are scaled to the domestic market may be forced out of the market due to poor economic returns. Over time, reservation policies would reduce the likelihood of new sources of gas being developed, to the detriment of the level and diversity of supply for domestic gas users.

In a market that is facing supply issues arising from LNG, moratoria, and a low oil price, further impediments to gas supply development would be detrimental and so should not be introduced.

Market developments compel the ACCC to revisit GBJV joint marketing arrangements

The effect of the current lack of diversity of suppliers in the southern states is exacerbated by the existing joint marketing arrangements of the GBJV. The ACCC conducted a preliminary review of the GBJV joint marketing arrangements in 2010. The ACCC decided to take no further action at that time, but advised the joint venture partners that it might revisit the matter if future market developments warranted doing so.

The Inquiry has found that the GBJV now holds significant market power as a result of the changed competitive dynamics in the southern states. The market has changed significantly since 2010, particularly for southern gas users. The Inquiry considers that joint marketing by the GBJV may have a more detrimental impact on competition than in the past and this issue warrants reconsideration by the ACCC.

Recommendations:

1. Governments should consider adopting regulatory regimes to manage the risks of individual gas supply projects on a case by case basis rather than using blanket moratoria. Governments should take into consideration the significant effects that moratoria and other restrictions on gas development may have on gas users.
2. Gas reservation policies should not be introduced, given their likely detrimental effect on already uncertain supply.

ACCC future work:

1. The ACCC will consider the competitive effect of the joint marketing arrangements of the GBJV in light of current market dynamics, for the purposes of s. 45 of the CCA.

2. Pipeline sector problems exacerbate gas supply and pricing issues in the domestic market

While the availability and diversity of gas supply is critical, the efficiency of the gas market is also critically dependent on the efficiency of the transmission sector, the prices pipeline operators charge for transportation services and the ability of this sector to respond to change.

Pipeline operators are responding to market needs but there is evidence of monopoly pricing giving rise to higher prices and economic inefficiencies

The demand for transportation services is changing and the level of flexibility required by some market participants is increasing. Pipeline operators have in general responded well to the changes underway, by offering more flexible services and carrying out major investments, most of which have been fully underwritten by medium- to long-term gas transportation agreements (GTAs) with shippers. These responses are providing for more dynamic pipeline flows and a greater degree of pipeline interconnection.

While pipeline operators have been responding to the changes, there is evidence that a large number of existing pipelines have been engaging in monopoly pricing. For example, the rates of return some pipeline operators have assumed when determining the price of access to the incremental investments that have occurred in the last three years are 1.4–20 times higher than the benchmark return on equity the Australian Energy Regulator (AER) has estimated in gas regulatory decisions over this period, despite these investments being usually fully underwritten

by shipper GTAs. They are also substantially higher than the return adopted in the winning bid for the NGP.

There is also evidence on some pipelines of excessive as available and interruptible charges and forward haul charges that are 2–5 times higher than they would be if the pipeline was regulated. One operator has also estimated it is earning 70 per cent more in overall pipeline revenue than it would if it was regulated. Another pipeline owner that is facing declining volumes is trying to maintain an overall rate of return that is 1.5 times higher than the return it estimated it would earn if it was subject to regulation.

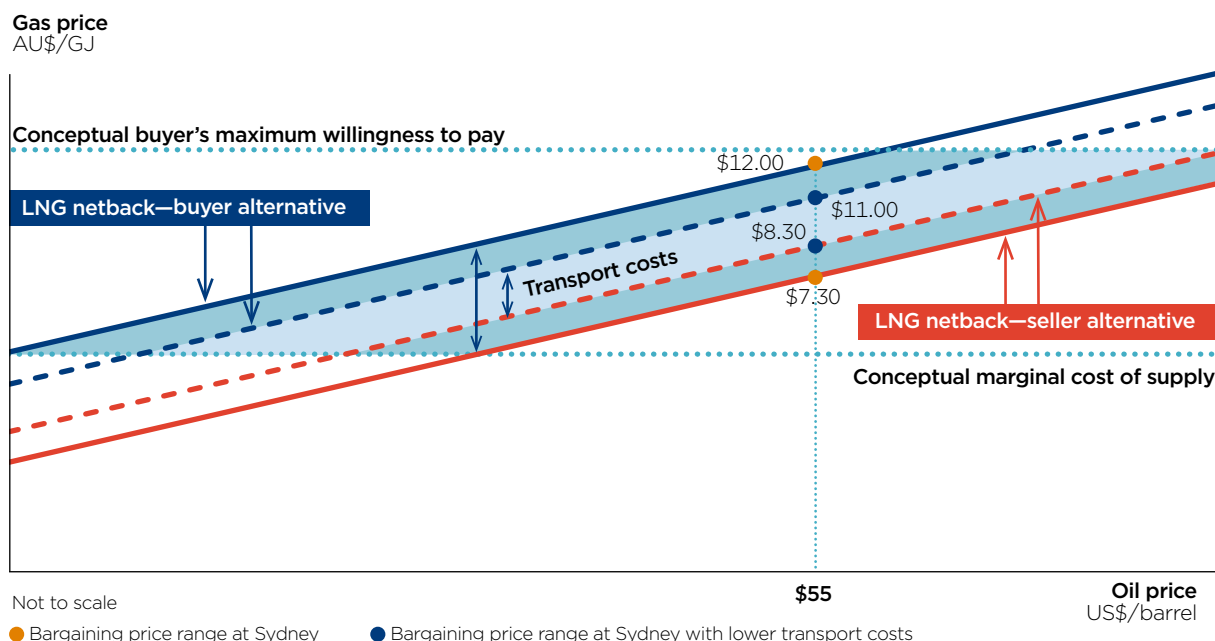
To be clear, monopoly pricing is not a contravention of the CCA. Further, it is legitimate and expected commercial behaviour. In a market economy where the profit motive drives private enterprise, it is expected that firms that do not face effective competition, or a threat of such competition, will engage in such behaviour. Monopoly pricing can, nevertheless, have a detrimental effect on economic efficiency and consumers.

Material gathered by the Inquiry indicates that monopoly pricing is giving rise to higher delivered gas prices for users and in some cases lower ex-plant prices for producers. This is, in turn, giving rise to a range of economic inefficiencies in the east coast gas market and in upstream and downstream markets, the costs of which will ultimately be borne by consumers. The Inquiry has also heard specific examples from market participants of excessive transportation charges resulting in:

- lower than efficient levels of investment in exploration and reserves development
- lower than efficient levels of gas use and investment in facilities that use gas
- distortions in gas flows across the market and gas failing to flow to where it is valued the most.

Under the bargaining framework presented in chart 4, monopoly pricing on pipelines between Wallumbilla and the southern states will also affect the range of possible gas price outcomes for domestic users even if buyers do not physically transport gas over these routes. This effect can be seen in chart 5, which shows that a reduction in transportation charges would narrow the range of possible pricing outcomes. In an environment where domestic gas users in the southern states are likely to pay a price approaching the buyer's alternative, eliminating the effect of monopoly pricing on transportation charges would reduce the buyer alternative and therefore reduce the maximum price in the bargaining price range. Where domestic gas prices will ultimately end up within the bargaining price range (for a given oil price) is likely to depend on a number of factors including the availability and diversity of gas supply in the southern states as well as on the level of the pipeline charges.

Chart 5: Bargaining framework for gas supply negotiations in Sydney with lower transport costs



Notes: Pipeline tariffs on each of the relevant pipelines (MSP, SWQP/QSN) were reduced by 50 per cent in this illustrative example. Transportation costs under the buyer's and seller's alternative include gas losses and in the case of the seller's alternative also include processing costs at Moomba. In this example, gas losses and processing costs are assumed to be unchanged.

The gas access regime is not constraining the behaviour of pipelines and should be strengthened

The ability and incentive of existing transmission pipelines to engage in monopoly pricing is not being effectively constrained by competition from other pipelines, competition from alternative energy sources, the risk of stranding, the countervailing power of shippers or the threat of regulation.

The transmission sector is already subject to an access regime under the National Gas Law (NGL) and the National Gas Rules (NGR), but less than 20 per cent of the transmission pipelines on the east coast are currently subject to any form of regulation. This is in stark contrast to other comparable jurisdictions, such as the United States, New Zealand and the European Union, where the vast majority of transmission pipelines are subject to economic regulation because it has been recognised that pipelines can wield substantial market power.

Not only are few transmission pipelines regulated, but the threat of regulation is also failing to impose an effective constraint on the behaviour of a number of unregulated pipelines. This is because the current test for regulation under the NGL (the 'coverage criteria'), which largely mirrors the declaration criteria in Part IIIA of the CCA, is unlikely to be met by the majority of transmission pipelines given the characteristics of the market. The criteria are also, as the Productivity Commission has noted⁹, not designed to address the market failure that has been observed in this Inquiry, which is monopoly pricing that gives rise to economic inefficiencies with little or no effect on the level of competition in dependent markets.

To address this limitation, the Inquiry recommends that the current test for regulation be replaced with a new test, which focuses on whether:

- 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

⁹ Productivity Commission, *Final Report: National Access Regime*, 25 October 2013, pp. 172–3. In this report, the Productivity Commission noted that tools other than Part IIIA may be required where an exercise of market power has no effect on competition in a dependent market:
"Where competition is not disrupted but monopoly pricing exists, it may be the case that a different form of intervention is justified. For example, some industries (such as airports) are subject to prices surveillance under Part VIIA of the CCA and declaration could supersede the use of these less intrusive approaches ... Monopoly pricing may also be addressed through pricing regulation under industryspecific access regimes (such as is the case for electricity networks)."

- 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).

In contrast to the coverage criteria, this test better reflects the characteristics of the market and will provide a more effective constraint on the behaviour of pipeline operators. The test is also consistent with the principles embodied in the NGO and policy makers' original intentions when implementing this regime.¹⁰

While the Inquiry is satisfied of the need to move to this new test, it has not been possible as part of this process to consult with market participants on the specific matters to be considered when applying this test or how it should be implemented. The Inquiry therefore recommends the AEMC be accorded responsibility for carrying out further consultation on these issues.

In addition to the limitation imposed by the current test for regulation discussed above, some features of the NGR mean that even if a pipeline is subject to full regulation, it may still be able to exercise market power. For example, expansions of a fully regulated pipeline may not be subject to regulation. Similarly, non-contestable services provided by a fully regulated pipeline may not be subject to an ex ante review by the AER.

Further, the limited availability of information on the costs pipeline owners incur in providing services and the relationship between these costs and the prices charged for services, may also be limiting the ability of shippers to determine whether or not the prices they are offered are cost reflective and to negotiate effectively with pipeline operators.

The Inquiry makes a number of recommendations on how to address these limitations.

Recommendations:

3. The COAG Energy Council should agree to replace the current test for the regulation of gas pipelines (the coverage criteria) in the NGL with a new test. This test would be triggered if the relevant Minister, having regard to the National Competition Council's recommendation, is satisfied that:

- 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 will or is likely to contribute to the achievement of the NGO.

The COAG Energy Council should also ask the AEMC to carry out further consultation on the specific matters that should be considered when applying this test and how it should be implemented and to advise the COAG Energy Council of the amendments that would need to be made to the NGL and the NGR to give effect to this new test.

4. The COAG Energy Council should ask the AEMC to review Parts 8–12 of the NGR and to make any amendments that may be required to address the concern that pipelines subject to full regulation may still be able to exercise market power to the detriment of consumers and economic efficiency. In carrying out this review, the AEMC should also consider whether any changes can be made to the dispute resolution mechanism in the NGL and NGR to make it more accessible to shippers, so that it provides a more effective constraint on the behaviour of pipeline operators.

¹⁰ The stated objective of the gas access regime, when it was originally implemented in 1997, was the establishment of a framework for third party access to gas pipelines that would, amongst other things, prevent the abuse of monopoly power by pipeline operators and provide rights of access on fair and reasonable terms for both the pipeline operator and users. See *National Third Party Access Code for Natural Gas Pipeline Systems*, November 1997 p. 1.

5. The COAG Energy Council should ask the AEMC to explore how the scope of the information disclosure requirements in the NGL should be expanded to require all pipelines operating on an open access basis (that is, regulated and unregulated pipelines) to publish financial information that shippers can use to determine whether or not the prices they are offered by pipeline operators are cost reflective. The publication of this information would enable shippers to negotiate more effectively with pipeline operators and to identify any exercise of market power more readily.

The Inquiry is cognisant of the effect that regulation can have on investment, innovation and the other costs and risks that regulation can expose parties to. There are, however, already sufficient safeguards in the NGL and NGR that are designed to ameliorate these effects, including, amongst others, the 15-year no-coverage option for greenfields pipelines, the protection the NGL accords commercially negotiated contracts, the possibility of full or light handed regulation and the availability of merits review. The Inquiry is not recommending any changes to these elements of the current regime.

3. Market operation and transparency should be improved

The AEMC has been undertaking its East Coast Wholesale Gas Market and Pipeline Frameworks Review at the same time as this Inquiry. The AEMC's focus has been on gas market design, including the further development of wholesale gas trading markets, improved pipeline access and improved information provision via the Bulletin Board. The Inquiry supports increased transparency and information in the market.

The Inquiry has focussed on three key areas to improve transparency and market operation:

- improving the effectiveness of supply signals by increasing transparency
- the role and evolution of risk management mechanisms in the market
- facilitating more efficient use of pipeline capacity and hub services.

The gas market is opaque and inflexible and is not signalling expected supply problems effectively

The east coast gas market lacks transparency in many areas, including the level of reserves and resources, current and expected future production, gas prices, transportation prices, and the level and availability of storage. Two areas in particular—the level of reserves and resources, and the lack of an indicative price for gas—greatly hinder the market's ability to respond to changes in gas availability and domestic gas prices.

Following the development of the LNG projects and the increased level of uncertainty in the market, these are now important issues that should be addressed.

Reporting of reserves and resources needs to be consistent and transparent

There is a lack of transparency around reporting of reserves and resources in the east coast gas market. Gas users lack clear insight into actual reserve positions when negotiating for new supply contracts which provides an advantage to large incumbents with greater knowledge of the market and reserve positions. Reserve calculations are based on a number of assumptions, including financial and oil price assumptions, which are often undisclosed. Recent impairments in reserve holdings by major oil and gas companies show the difficulty in relying on reserve statements when assumptions are not known.

There is no clear, consistent and accurate reporting of information on reserves and resources. The Australian Stock Exchange (ASX) reporting requirements only apply to listed companies, and different listed companies report at different times and at different levels of geographical aggregation. Unlisted companies and those listed overseas may not report at all, making it hard to assess reserves and resources on a field, basin or state basis. While there are private providers of market information, they also rely on incomplete and imperfect information, supplemented by assumptions.

In addition, the states, territories and the Commonwealth all collect their own geological information and reserve and resource data. The requirements for companies to supply this are inconsistent across jurisdictions and the release of information publicly by each jurisdiction varies widely. The sharing of information and data between jurisdictions is also inconsistent and limited.

Standardised reporting (one standard not many) would benefit producers, users, policy makers, and potential new participants in the market. Policy decisions based on inconsistent or inadequate information and data are more likely to result in unwanted ramifications, unintended consequences and poor policy outcomes for the market.

Recommendations:

6. All explorers and producers, including non-ASX listed companies, should report consistent reserve and resource information across the east coast gas market. Reporting should be based on common price assumptions in the calculation of reserves and resources. Gas reserve and resource information should be displayed on the Gas Market Bulletin Board consistent with the COAG Energy Council Gas Market Development Plan to enhance the market information available to Bulletin Board users.
7. The COAG Energy Council should ensure that the geological and reserve/resource information collected by the states and territories and the Commonwealth, is consistent, non-duplicative and shared. Where this information is made public, the Energy Council should ensure that it is in a consistent format.

Improved price information would promote competitive bargaining

Information about gas prices is partial, provisional and mostly private. These pricing information gaps impair bargaining. A lot of pricing information is private and particular to specific contracts and negotiations. Because of this, there is a large disparity between the level and accuracy of information available to participants such as producers and retailers that participate in many trades, are larger or are more vertically integrated, and participants such as industrial gas users that are inevitably less frequently parties to negotiations and agreements. While some disparity has always existed, the disparity widens when the number of offers made by suppliers is reduced. When few offers are being made, industrial users have less information to work with.

Currently, no accurate and useful indicative price is readily available to the market. Confidential bilateral contracts continue to dominate, giving participants limited insight into pricing levels. Markets and hubs remain relatively thinly traded, so prices may not be representative. While a gas futures market is emerging, it has limited depth so far. There is limited shared understanding of what LNG netback price means for domestic gas market participants, how it is calculated, and how it should be reflected in the domestic market. This lack of readily available pricing information also favours large incumbents in price negotiations.

The AEMC is working on ways to develop a more liquid hub-based indicative price, but this is likely to take some time to emerge. The ABS is investigating a gas price index, which would show price trends, but not absolute prices. Developing and publishing other indicative prices would enhance market transparency.

Recommendations:

8. AEMO should develop and publish a monthly LNG netback price to Wallumbilla, with a clear explanatory framework and inputs.
9. The AEMC should consult with gas users about the potential benefits of requiring AEMO or the AER to publish a periodic price series of actual commodity gas prices paid to producers, either for the east coast generally or for Victoria and Queensland. Any price series should be weighted by volume and be based on commonly observed take or pay percentages and load factors.

Risk management mechanisms are evolving and proposed new mechanisms should be supported

The evolving gas market has created new challenges for users. Suppliers and users are responding to the changes in market conditions by altering their approach to contracting. Some risks are being shifted from producers to gas buyers. As a result, buyers are being forced to adopt alternative approaches to manage their exposure.

The scope for gas users to manage demand variations through GSAs is diminishing as producers offer contracts of shorter duration, with less volume flexibility. To the extent that contractual flexibility is available, it is becoming more expensive.

Storage and short-term trading options are increasingly important to users due to the reduction in contractual flexibility, particularly for gas buyers in the southern states with flexible loads. Demand for storage is expected to increase. It is important to monitor potential barriers to accessing storage, particularly in southern markets. At present, there is no evidence that access to storage capacity on reasonable terms is a significant barrier to entry to smaller retailers in the east coast gas market, but this may become a more significant issue in the future if the volume of gas available for supply into the market increases.

Measures to promote greater liquidity in short term trading markets should be encouraged. Some gas market participants in the east coast gas market are trading gas on the existing Declared Wholesale Gas Market (DWGM), the Short Term Trading Markets (STTMs), and/or the Wallumbilla Gas Supply Hub (GSH), to support their gas volume requirements. This strategy is most suitable for buyers with significant flexibility in their day-to-day gas demand requirements. A lack of confidence and liquidity in these markets is a disincentive for gas producers and gas users to increase their reliance on gas trading. The AEMC's Draft Stage 2 report outlines several proposed current and potential reforms to market operations:

- Reform the existing DWGM in Victoria to establish a cleaner wholesale market price.
- Further develop the Wallumbilla GSH if trading liquidity does not emerge.
- Allow an opportunity for the Moomba hub proposed for 2016 to develop but review whether one or two northern hubs would best promote liquidity.

Greater liquidity in wholesale gas markets would improve price discovery and help market participants to manage volume fluctuations. It would also facilitate new entry by retailers in downstream gas markets. The Inquiry supports the AEMC's wide consideration of market participant views on the appropriate number and type (voluntary or mandatory) of trading markets. Some market participants may favour existing STTM and DWGM arrangements because they have found sufficient liquidity to participate in them to date, but the AEMC should test whether other arrangements could generate more liquidity.

To increase participation in trading markets, steps can and should be taken to reduce the transaction costs associated with trading in those markets, including the costs of transporting gas to them. In the long run, however, significant improvement in participation and liquidity will be best supported by an increase in the diversity of gas market participants and the volume of gas in the market. Forcing producers to sell into trading markets in place of supply under GSAs to retailers is not supported.

Recommendation:

10. The AEMC should consider how to monitor changes in the level of trading flexibility available to gas buyers over time, and how the trading and other risks of having to purchase gas and transportation services on a day-ahead basis can best be managed.

The gas specification may affect market liquidity

Gas specification is an emerging issue that may affect market liquidity in the future. Gas from different reservoirs and basins varies in composition. Gas from the Queensland CSG fields is a dry gas with low levels of heavier hydrocarbons. While CSG is interchangeable with conventional gas from the Cooper Basin or the offshore gas basins for most domestic gas users, the

Queensland LNG projects have been designed for a dry gas such as CSG as feedstock. This distinction is leading to potential gas specification issues that could bifurcate the east coast gas market. If this occurs, gas users in Queensland may have to pay additional processing costs to meet a standard that is not required for their use.

Recommendation:

11. The COAG Energy Council should monitor the emerging issue of separate gas specifications in the east coast gas market. This issue has the potential to impede the free flow of gas across the east coast gas market and impose additional costs on some market participants. The COAG Energy Council should ensure that any costs associated with a non-standard gas specification are borne by the market participants that require that alternative specification.

Transportation capacity and hub services can be further unlocked to increase efficient use

Increasing and improving access to secondary pipeline capacity and hub services would increase efficiency in the pipeline sector.

Secondary trading of pipeline capacity should be streamlined

Gas transportation is dominated by long-term bilateral trades. Some secondary trading is occurring across the entire east coast but short-term trades are less widespread, occurring mostly in Queensland and South Australia.

The Inquiry has not found evidence that provisions within GTAs prevent secondary trading. There is also no evidence of systemic withholding of capacity on major transmission pipelines.

There is, however, evidence of retailers withholding capacity on some smaller regional pipelines where a retailer has contracted all the capacity. There is no transparency around the utilisation of regional pipelines, which puts industrial users at a disadvantage when negotiating access to pipeline capacity. Withholding of capacity on regional pipelines by incumbents is restricting competition for supply from other retailers.

Some pipeline operators are charging high prices for access to secondary (as available or interruptible) capacity. This indicates a lack of competition between pipeline operators and shippers for secondary capacity. There are situations where a pipeline operator is inserting itself between a willing seller and buyer of excess capacity, increasing the costs, time taken, and transaction effort for the seller and buyer. For example, gas trade may be restricted until both buyer and seller register the delivery point.

The AEMC has proposed:

- A capacity trading platform that shippers can use to trade secondary capacity anonymously up to the nomination cut-off time.
- A compulsory day-ahead auction for contracted but un-nominated pipeline capacity that would be triggered after the nomination cut-off time.

It has also proposed reforms to make contract terms and conditions for trade more standardised. The Inquiry supports these proposals as they are likely to increase the trade of secondary capacity. Participants identified to the Inquiry difficulties in jointly coordinating commodity and transportation, and coordinating transport across multiple asset owners. This suggests potential benefits from centralised platforms for trading commodity and transportation. However, a broader cost-benefit assessment of the auction before implementation would be beneficial and should include the effects on the flexibility of the gas and electricity markets.

The Inquiry has found that short-term trades can occur relatively quickly if a master agreement is in place, with terms and conditions agreed. This suggests that reforms to standardise terms in primary and secondary capacity contracts may result in large benefits, regardless of whether the auction proposal proceeds.

Recommendation:

12. The AEMC should consider requiring the introduction of a centralised capacity trading platform to facilitate secondary capacity trading and day-ahead auctioning of unutilised capacity.

ACCC future work:

2. The ACCC will consider whether the availability or pricing of capacity on regional pipelines raises any concerns as a possible contravention of the misuse of market power provisions or the exclusive dealing provisions of the CCA.

Competition for gas hub services should be promoted

Hub services (compression and redirection services) are an increasingly important component of the east coast gas market. Hub services are often bundled with transportation, but are increasingly being priced separately. Prices for services at the Wallumbilla GSH are high, particularly for interruptible services, which are sold by the owner of the assets providing these services. The high interruptible pricing indicates the three parties holding all the contracted capacity may not currently be competing with the asset owner. AEMO's optional hub services model, which will introduce a trading platform for spare capacity may help promote more trade and competition. The Inquiry considers that auctioning of unutilised capacity, if recommended for pipelines, should also be introduced for hubs.

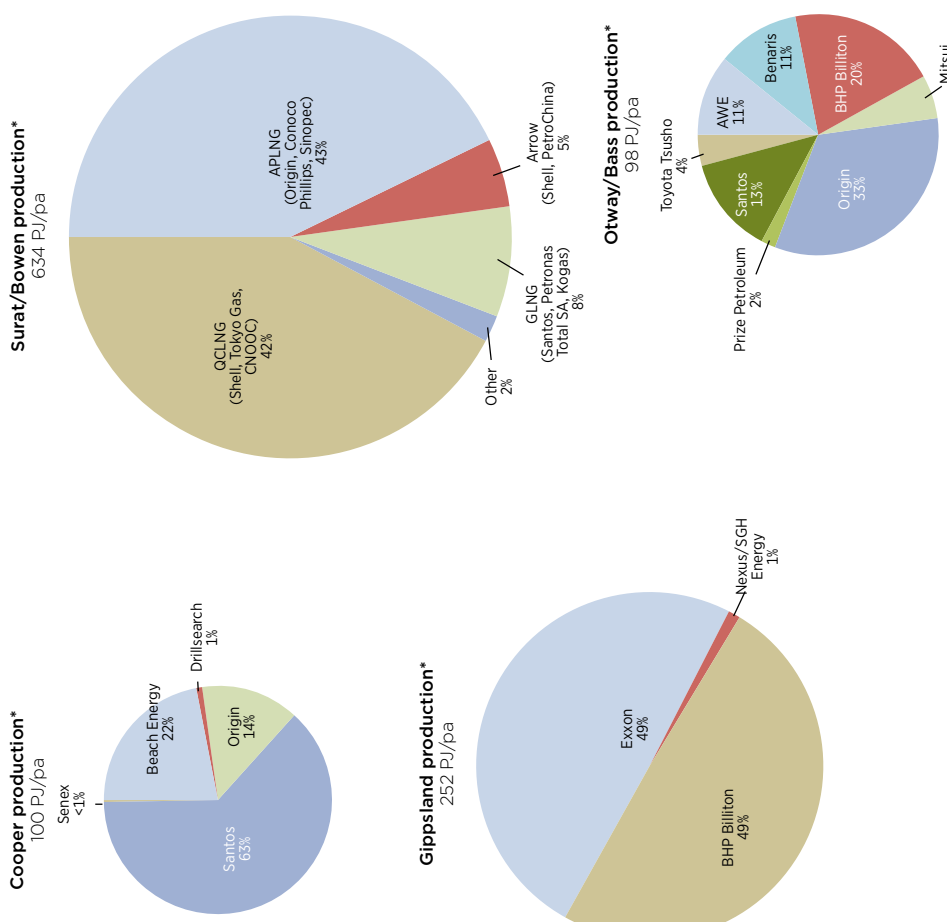
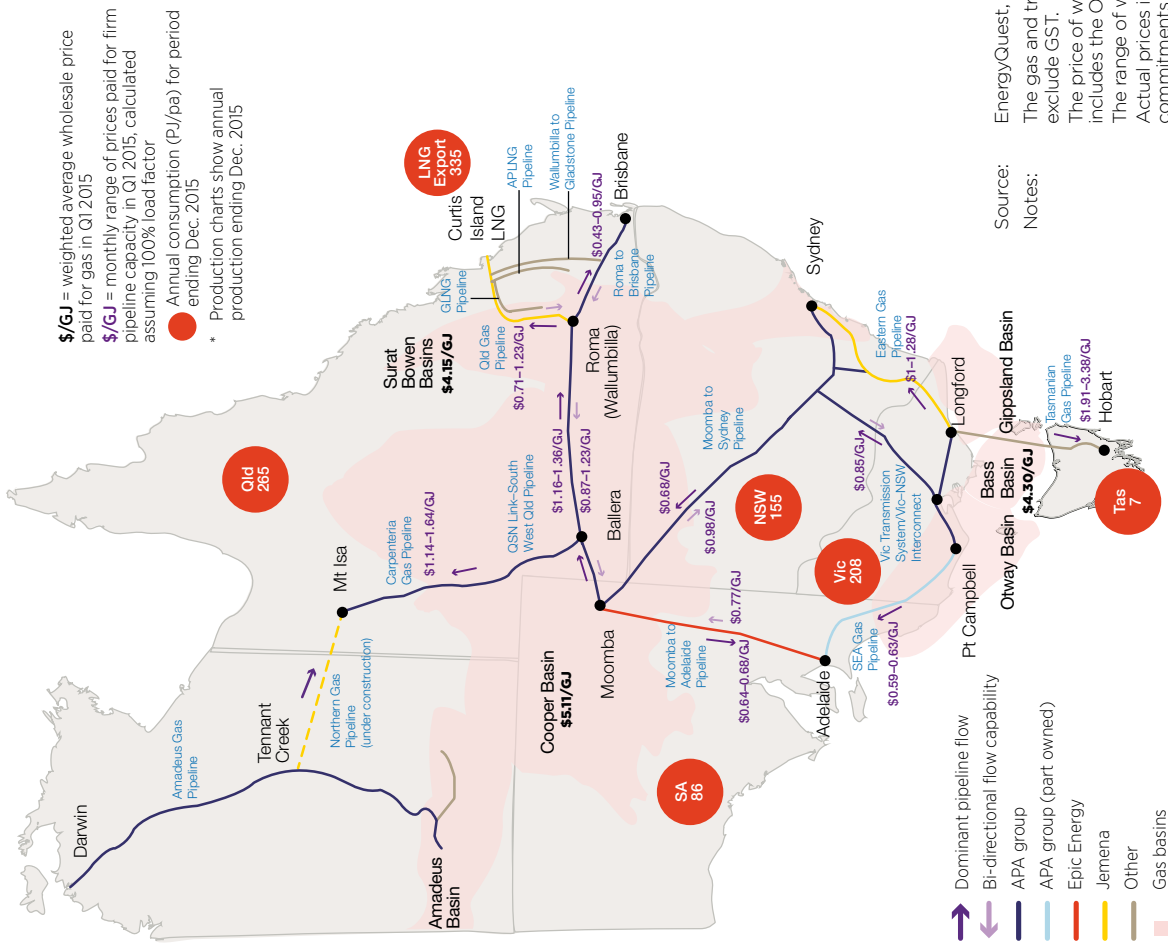
APA has taken steps, in conjunction with AEMO, to improve transparency around gas flows into the Wallumbilla compound which services the Wallumbilla GSH. Some concerns remain, however, about the visibility and pricing of the actual hub services being delivered.

Recommendation:

13. The AEMC should consider the benefits of a short-term auction process for hub services if it decides to implement the day-ahead auction for pipeline services.

The east coast gas market has changed fundamentally, and will not change back to its previous dynamics. The development of the LNG projects has permanently changed the way the gas market operates. The transition has been, and will continue to be difficult for many participants. It is encouraging that changes are already happening to improve the operation of the market, driven both by participants and the AEMC. This Inquiry used the ACCC's compulsory information gathering powers to understand the true dynamics of the market. The Inquiry's findings will inform participants and policy makers, while the specific recommendations, if implemented, will lead to a better functioning and more competitive market.

Figure 1: Pipeline network and gas production



Source: EnergyQuest, *EnergyQuarterly*, March 2016. EnergyQuest unpublished production data and published consumption data. Notes: The gas and transportation prices are based on invoices in Q1 2015 provided by producers and pipeline operators, and exclude GST. The price of wholesale gas is an average, weighted by actual volume supplied in the relevant period. The price for Victoria includes the Otway, Bass and Gippsland basins. The price for the Cooper Basin includes three suppliers. The range of wholesale gas prices across basins is \$2.10–\$10.09/GJ. Actual prices in GSAs and GTAs vary due to differences in key commercial terms, including load factor, take-or-pay or capacity commitments, contract length, and the time at which the prices were agreed or reviewed.

East Coast Gas Inquiry key findings

Gas supply

1. Domestic purchasers of gas, particularly industrial users, experienced an unprecedented change in their ability to obtain gas, especially in the period from about 2012 to the end of 2014 for gas to be supplied in 2016 and beyond. When seeking gas they received few, if any, real offers. Offers received were high priced, with limited volumes over shorter periods of time, had more restrictive terms and conditions and some were on 'take it or leave it' terms.
2. More gas supply offers are now available, but at higher prices, for shorter durations and with more restrictive non-price terms and conditions. Domestic industrial users may have seen margin reductions of 0.6–6.0 percentage points, depending on the industry and the wholesale gas price increases. Household gas bills may increase by 5 per cent in New South Wales and 11 per cent in Victoria with wholesale gas price increases of, for example, \$2/GJ.
3. The reliability of future gas supply is affected by three significant factors coinciding:
 - Significant demand from the LNG projects, which has diverted gas from traditional sources of domestic supply.
 - Low oil prices reducing the ability and incentive of producers across the entire east coast gas market to explore for and develop gas.
 - Moratoria on onshore gas exploration and development and other regulatory restrictions in New South Wales, Victoria and Tasmania, and potentially the Northern Territory, prohibiting new gas supply.
4. The future supply outlook is uncertain. Future domestic and LNG demand will require extensive development of undeveloped gas reserves. Sufficient gas is currently forecast to be produced in the east coast gas market to meet domestic demand and existing LNG contract commitments until at least 2025, but there is uncertainty over the timing of some developments, particularly due to low oil prices.
5. There is a need for more sources of gas supply, particularly in the southern states. The gas users in these states are becoming overly dependent on the jointly marketed GBJV gas. If their alternative to dealing with the GBJV is to transport gas from Queensland, southern users may have to pay considerably more for gas than they are otherwise likely to pay in a competitive market. This is exacerbated by the high cost of transportation. Increasing the level and diversity of supply, located close to southern demand centres, will improve the competitive dynamics in the south and is likely to lead to better pricing outcomes for domestic users.

Gas transportation

6. Pipeline operators have responded to the changes underway in the market. There is, however, evidence that a large number of pipeline operators have been engaging in monopoly pricing. This gives rise to higher delivered gas prices and is having an adverse effect on the economic efficiency of the east coast gas market and upstream and downstream markets, the costs of which will ultimately be borne by consumers. There is also evidence that the ability and incentive of existing pipeline operators to engage in this behaviour is not being effectively constrained by competition from other pipelines, competition from alternative energy sources, the risk of stranding, the countervailing power of shippers, regulation or the threat of regulation.
7. The current gas access regime is not imposing an effective constraint on the behaviour of a number of unregulated pipelines. The current test for regulation under the National Gas Law (NGL) (the coverage criteria) is not designed to address the market failure that has been observed in this Inquiry, that is, monopoly pricing that results in economic inefficiencies with little or no effect on the level of competition in dependent markets. Other gaps in the regulatory framework are also allowing pipelines that are subject to regulation to continue to engage in monopoly pricing. Information asymmetries are limiting the ability of shippers to identify any exercise of market power and to negotiate effectively with pipeline operators.

8. Less than 20 per cent of the transmission pipelines on the east coast are currently subject to regulation under the NGL and National Gas Rules (NGR). This is in direct contrast to other comparable jurisdictions, such as the United States, the European Union and New Zealand, where the vast majority of transmission pipelines are regulated. It is well recognised in these jurisdictions that pipelines can wield substantial market power even where producers and users have a number of transportation options.

Market operation and the level of market transparency

9. The gas specification required by the LNG projects is different to the specification required by other gas users. This difference has the potential to impede the free flow of gas across the east coast gas market and impose additional costs on some market participants, potentially bifurcating the market, and reducing liquidity and opportunities for trading and arbitrage.
10. Lack of transparency and information about the level of reserves, and commodity and transport prices are hindering efficient market responses to the changing conditions and are not signalling expected supply problems effectively.
11. Trading of longer-term capacity held by shippers is occurring across the east coast. Shorter-term capacity trades are also occurring but not on all pipelines. There is no evidence of withholding of capacity by shippers on major east coast pipelines.
12. However, there is evidence that capacity is being withheld by incumbents on some regional pipelines, which is restricting competition for supply from other retailers.
13. APA has taken steps, in conjunction with AEMO, to improve transparency around gas flows into the Wallumbilla compound which services the Wallumbilla GSH. Some concerns remain as to the transparency of actual hub services being delivered and the pricing of those services.
14. Risk management mechanisms are becoming more important for buyers, and especially industrial users, as the terms and conditions of supply are tightened by suppliers. These include storage and gas trading mechanisms such as the STTMs. The liquidity of gas trading mechanisms is currently limited. In the long-run, liquidity will be best supported by an increase in the diversity of gas market participants and the volume of gas supply in the market overall. At present, there is no evidence that access to storage capacity on reasonable terms is a significant barrier to entry by smaller retailers in the east coast gas market. This may become a more significant issue in the future if the volume of gas available for supply into the market increases.

East Coast Gas Inquiry recommendations

Gas supply

1. Governments should consider adopting regulatory regimes to manage the risks of individual gas supply projects on a case by case basis rather than using blanket moratoria. Governments should take into consideration the significant effects that moratoria and other restrictions on gas development may have on gas users.
2. Gas reservation policies should not be introduced, given their likely detrimental effect on already uncertain supply.

Gas transportation

3. The COAG Energy Council should agree to replace the current test for the regulation of gas pipelines (the coverage criteria) in the NGL with a new test. This test would be triggered if the relevant Minister, having regard to the National Competition Council's recommendation, is satisfied that:
 - 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, and
 - coverage will or is likely to contribute to the achievement of the National Gas Objective.The COAG Energy Council should also ask the AEMC to carry out further consultation on the specific matters that should be considered when applying this test and how it should be implemented and to advise the COAG Energy Council of the amendments that would need to be made to the NGL and the NGR to give effect to this new test.
4. The COAG Energy Council should ask the AEMC to review Parts 8-12 of the NGR and to make any amendments that may be required to address the concern that pipelines subject to full regulation may still be able to exercise market power to the detriment of consumers and economic efficiency. In carrying out this review, the AEMC should also consider whether any changes can be made to the dispute resolution mechanism in the NGL and NGR to make it more accessible to shippers, so that it provides a more effective constraint on the behaviour of pipeline operators.
5. The COAG Energy Council should ask the AEMC to explore how the scope of the information disclosure requirements in the NGL should be expanded to require all pipelines operating on an open access basis (that is, regulated and unregulated pipelines) to publish financial information that shippers can use to determine whether or not the prices they are offered by pipeline operators are cost reflective. The publication of this information would enable shippers to negotiate more effectively with pipeline operators and to identify any exercise of market power more readily.

Market operation and the level of market transparency

6. All explorers and producers, including non-ASX listed companies, should report consistent reserve and resource information across the east coast gas market. Reporting should be based on common price assumptions in the calculation of reserves and resources. Gas reserve and resource information should be displayed on the Gas Market Bulletin Board consistent with the COAG Energy Council Gas Market Development Plan to enhance the market information available to Bulletin Board users.
7. The COAG Energy Council should ensure that the geological and reserve/resource information collected by the states and territories and the Commonwealth, is consistent, non-duplicative and shared. Where this information is made public, the Energy Council should ensure that it is in a consistent format.
8. AEMO should develop and publish a monthly LNG netback price to Wallumbilla, with a clear explanatory framework and inputs.

9. The AEMC should consult with gas users about the potential benefits of requiring AEMO or the AER to publish a periodic price series of actual commodity gas prices paid to producers, either for the east coast generally or for Victoria and Queensland. Any price series should be weighted by volume and be based on commonly observed take or pay percentages and load factors.
10. The AEMC should consider how to monitor changes in the level of trading flexibility available to gas buyers over time, and how the trading and other risks of having to purchase gas and transportation services on a day-ahead basis can best be managed.
11. The COAG Energy Council should monitor the emerging issue of separate gas specifications in the east coast gas market. This issue has the potential to impede the free flow of gas across the east coast gas market and impose additional costs on some market participants. The COAG Energy Council should ensure that any costs associated with a non-standard gas specification are borne by the market participants that require that alternative specification.
12. The AEMC should consider requiring the introduction of a centralised capacity trading platform to facilitate secondary capacity trading and day-ahead auctioning of unutilised capacity.
13. The AEMC should consider the benefits of a short-term auction process for hub services if it decides to implement the day-ahead auction for pipeline services.

ACCC future work

1. The ACCC will consider the competitive effect of joint marketing arrangements of the GBJV in light of current market dynamics, for the purposes of s. 45 of the CCA.
2. The ACCC will consider whether the availability or pricing of capacity on regional pipelines raises any concerns as a breach of the misuse of market power provisions or the exclusive dealing provisions of the CCA.

Background

There has been significant industry and public concern regarding the competitive dynamics of the east coast gas market. The development of liquefied natural gas (LNG) export projects in Queensland has exposed domestic gas users to international gas prices for the first time and there are increased uncertainties about the future availability of gas for domestic use.

Various public inquiries and reports have been carried out or commissioned by Commonwealth and state governments, triggered by LNG developments and the concerns of industry participants about the effect of these developments on their businesses.¹¹ These inquiries and reports have examined various aspects of the supply of gas in the east coast gas market and often involved public consultations. A list of a number of these inquiries and reports is at appendix 1.

Many of these inquiries and reports commented that domestic gas users had experienced difficulties in finding reasonable gas supply offers and raised concerns about rapidly increasing gas prices and deteriorating non-price terms and conditions. A number of inquiries recommended a review of the state of competition in the domestic gas industry to identify and assess the presence of any market power, and any exercise of such power, particularly resulting from the developments triggered by the LNG projects.

Previous inquiries into the supply of wholesale gas in the east coast gas market received conflicting reports from gas suppliers, their associations and gas users about prevailing supply and demand conditions, the extent of active gas supply negotiations and the supply outcomes. It was difficult for these inquiries to assess competing claims about these issues as critical information about gas supply agreements and contractual negotiations, including price and other terms, was unavailable due to confidentiality restrictions.

On 13 April 2015, the Australian Competition and Consumer Commission (ACCC) received a notice from the Minister for Small Business that required it to undertake an inquiry into the competitiveness of wholesale gas prices and the structure of the gas industry (the Inquiry) under Part VIIA of the *Competition and Consumer Act 2010* (Cth) (CCA). A copy of this letter, attaching the terms of reference for the Inquiry, is at appendix 2. The ACCC was required to give the report to the Minister within 12 months of the receipt of the notice.

The Inquiry commenced on 21 April 2015 with the publication of an inquiry notice in the *Australian Government Gazette* and in newspapers.

The Inquiry was conducted by the Chairman of the ACCC, Mr Rod Sims, and Commissioners Dr Jill Walker and Mr Roger Featherston.

Outline of the Inquiry process

As noted above, the ACCC held the Inquiry in accordance with the public inquiry powers contained in Part VIIA of the CCA.

Submissions

The ACCC released an issues paper on 4 June 2015. It outlined the issues on which the ACCC was seeking information and comments and described how submissions to the Inquiry could be made. The ACCC received 36 public submissions. A wide range of interested parties made submissions, including producers, retailers, users and industry representative groups. A list of parties who made public submissions is at appendix 3. All public submissions are available on the ACCC's website.¹²

11 This includes inquiries previously conducted by the Commonwealth Department of Industry and Science, the Productivity Commission, the Australian Energy Market Commission (AEMC), the NSW Legislative Council Select Committee and the Victorian Gas Market Taskforce. The AEMC is currently conducting its East Coast Wholesale Gas Market and Pipeline Framework Review and a Review of the Victorian Declared Wholesale Gas Market (together, the AEMC East Coast Gas Market Review).

12 See <https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015/issues-paper>.

A number of parties also provided submissions which they requested be treated as confidential.

Information, documents, hearings, and confidentiality

The ACCC also exercised its information gathering powers under the CCA. Amongst other things, these provisions enable the ACCC to issue notices to obtain information and documents¹³ and to summon a person to appear at an inquiry to give evidence and produce documents.¹⁴ The ACCC also consulted informally with a number of interested parties, and obtained data from several industry data providers.

The Inquiry conducted two public hearings, in Melbourne on 31 July 2015 and in Sydney on 31 August 2015. Representatives of nine interested parties gave evidence at these hearings. The transcripts of these hearings are available on the ACCC's website.¹⁵ The ACCC issued a number of notices to obtain confidential information and documents, and summoned a number of witnesses to give evidence and produce documents at a hearing. These hearings were held in private.

These processes have enabled the ACCC to investigate issues that are commercially sensitive to witnesses and other interested parties providing submissions, without affecting the competitive position and commercial relationships of those parties. This report discloses some aspects of the material obtained via these processes where the ACCC considers such disclosure would be in the public interest, even though the relevant party has not agreed to the disclosure. In these instances, the ACCC consulted with the relevant witness and/or their company (as appropriate) before doing so.

In total, the ACCC held 30 private hearings with gas producers, gas retailers and gas customers, consulted with over 50 interested parties and received around 73 000 documents (including contracts and invoices, internal company reports and correspondence, and other internal company documents).

The ACCC wishes to thank the industry for its considerable assistance and cooperation throughout the Inquiry.

Structure of the report

This report is presented in three sections. The first section, which is the focus of chapters 1 to 3, considers various issues relating to the availability and supply of gas as a commodity. This includes analysis of gas development, gas production and the dynamics of past, present and likely future commodity gas pricing in the east coast gas market.

The second section, which is the focus of chapters 4 and 5, considers the mechanisms available to gas buyers for managing the risks associated with the changing dynamics of gas availability and pricing in the east coast gas market, and possible steps that could be taken to improve the levels of flexibility and transparency available to participants in the east coast gas market.

The third section, which is the focus of chapters 6 to 8, considers various issues relating to the transportation of gas from gas fields to the locations where gas is consumed by users. This includes an assessment of the market power of gas pipeline operators and of whether current regulatory settings for gas transportation services are appropriate.

In preparing this report, the ACCC has been conscious that many aspects of the east coast gas market have been explored in considerable depth in previous inquiries. The ACCC has not sought to replicate the output of those inquiries, including information about the state of the gas market that has been made publicly available as result of those inquiries. Instead, it has focused on assessing and evaluating the specific additional information that it has been able to obtain under Part VIIA of the CCA, and on using that information to evaluate competing claims about market dynamics, market conditions, and the behaviour of market participants.

¹³ Section 95ZK of the CCA.

¹⁴ Section 95S of the CCA.

¹⁵ See <https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015/sydney-public-hearing> and <https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015/melbourne-public-hearing>.

1 The development of LNG triggered significant structural changes in the east coast gas market

Since the first cargo of LNG was exported from Curtis Island in Queensland on 6 January 2015, four of the six trains at the three LNG projects under construction have commenced production. While not all the LNG projects have reached peak production, they have triggered significant structural changes in the east coast gas market.¹⁶

It is uncertain if the rapid growth in the combined demand of the three LNG projects will be matched by an increase in gas production over the life of the LNG projects. This has precipitated uncertainty about the future supply-demand balance in the east coast gas market. This uncertainty has been exacerbated by GLNG purchasing substantial volumes of gas in the domestic market over the past five years to supplement production from its currently inadequate reserves. A large portion of this gas is from the Cooper Basin which historically supplied the southern domestic market. These purchases are reducing the volume of gas available to the domestic market and disrupting gas flows in the southern states.

Coinciding with the growing uncertainty about future gas availability, many long-term domestic GSAs expire over the years 2016 through 2018. Anticipating potential gas supply challenges, a number of industrial gas users approached gas suppliers in the period from about 2012 to the end of 2014 to secure gas for supply in 2016 and beyond. Many quickly found that they had fewer options for gas supply than previously and some users encountered difficulties getting any offers at all for supply in certain periods. Where offers were made, they were often at substantially higher prices and on less flexible terms than in the past. On occasions, a lack of clear communication from gas suppliers amplified user concerns and uncertainty about the state of the gas market.

While the gas market is gradually settling down, uncertainties about supply availability and pricing persist. Industrial gas users are now exposed to higher and more volatile domestic prices, which are influenced by fluctuating international LNG and world oil prices. This is likely to remain a feature of the east coast gas market into the future. Recent low oil prices have provided some price relief, but have also stifled investment required to bring on additional gas, which perpetuates uncertainties about availability of gas. Industrial users are adapting their practices for acquiring gas in response to increased pricing and supply uncertainties, but limited publicly available information and risk management mechanisms are making this challenging.

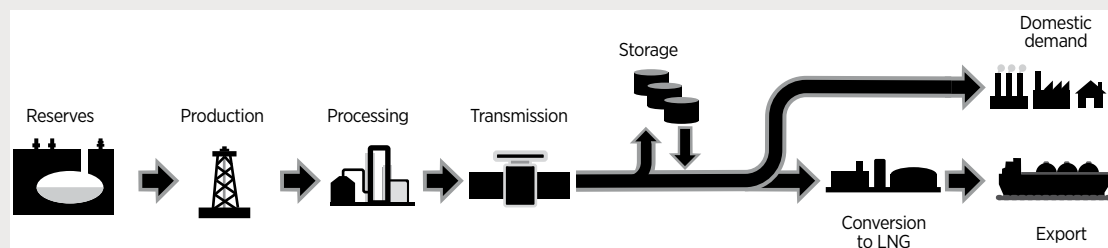
While the LNG projects have created difficulties for industrial users in the short term, they have also encouraged and accelerated market developments that may benefit all market participants in the long-run. The LNG projects have accelerated growth and development of the gas reserves base across the east coast gas market, although this has also contributed to the rapid rise in long-run marginal production costs. The surge in the growth of gas production and the emerging need of some gas suppliers to transport gas across the east coast gas market has led to various transmission pipelines being built, expanded or modified to flow in both directions, which has increased the connectivity of the transmission pipeline network in the east coast gas market. It has also led to the establishment of the Wallumbilla Gas Supply Hub (Wallumbilla GSH) and some market participants relying more on short-term trading markets.

Box 1.1 provides an overview of the gas supply chain in the east coast gas market.

¹⁶ The 'east coast gas market' is a phrase that has been adopted for the purpose of this Inquiry to describe a geographic area that includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania. It is not an economic or legal definition of any market for CCA purposes.

Box 1.1: The gas supply chain in the east coast gas market

There are a number of steps in the east coast gas market that need to be undertaken for gas to be supplied to end users.



Source: Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, March 2015, p. 26

Gas supply begins with the exploration and appraisal of potential gas sources to prove the presence of commercially viable gas reserves. In production projects, gas is extracted through wells and processed to separate methane from impurities (such as nitrogen, carbon dioxide or sulphur dioxide) and any produced water is removed and treated. In some fields, gas production is also associated with the production of other valuable petroleum products including crude oil, condensate (light oils) and natural gas liquids (for example, ethane, propane, butane, isobutane and pentane).

The processed gas is transported through high pressure transmission pipelines to demand centres—cities, regional areas and the LNG export facilities. Most large industrial gas users draw their gas directly from transmission pipelines.

At each domestic demand centre, the transmission pipelines connect to low pressure distribution networks. The distribution network is then used to deliver gas to smaller industrial and commercial users and households. Energy retailers typically purchase gas from producers, package it with transmission and distribution services and sell to residential, commercial and smaller industrial customers.

Storage facilities (either underground depleted gas fields or domestic LNG storage) and typically located close to demand or production centres and are used to augment supply at times of peak demand and manage variations in gas production.

At the LNG facilities in Gladstone, the gas is cooled and condensed into a liquid, loaded onto specially designed ships and transported to destination ports mostly in Asia. At the destination port, the LNG is stored, regasified and then injected into local distribution networks.

1.1 The LNG projects have disrupted the gas supply–demand balance in the east coast gas market

1.1.1 Growth in gas production may not match the growth in gas demand

The simultaneous construction of the three LNG projects in Queensland has created a rapid surge in demand in the east coast gas market. The total volume of gas consumed by domestic users in 2014, prior to commencement of export, was about 700 PJ per annum.¹⁷ By the time all six LNG trains in Queensland reach full production in 2017–18, the total demand on the east coast will rise to about 1750–2200 PJ per annum.¹⁸ Given this rapid growth, timely development of gas resources on the east coast is critical to ensuring that adequate supply is available for both domestic gas users and LNG exports.

17 Based on data from AEMO's *2015 National Gas Forecasting Report* and includes commercial and residential customers, industrial companies and gas powered electricity generators.

18 Based on data from AEMO's *2015 National Gas Forecasting Report* and data collected by the Inquiry.

There are substantial 2P gas reserves and 2C resources available in the east coast gas market (table 1.1).¹⁹ However, the timing of the development of 2P reserves that have not been committed to production and 2C resources will ultimately depend on the economics of developing these reserves and resources when they are required.

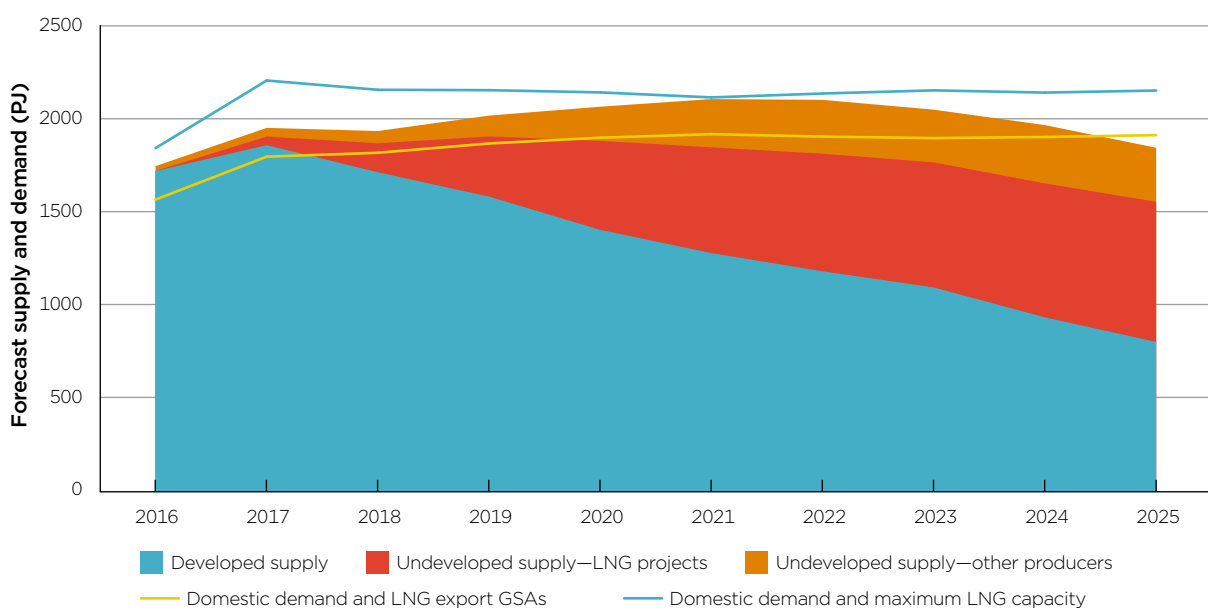
Table 1.1 2P reserves and 2C resources on the east coast as at February 2016

	2P reserves (PJ)	2C resources (PJ)
Coal seam gas (CSG)	41 833	25 878
Conventional	4 848	5 056
Shale and other	108	8429
Total	46 789	39 363

Source: EnergyQuest, *EnergyQuarterly*, March 2016.

Chart 1.1 shows the projected medium-term supply and demand forecast in the east coast gas market. This chart excludes the CSG reserves held by the Arrow Project, a 50/50 joint venture between Shell and PetroChina, as its commercial plans have not yet been announced following the merger between Shell and BG. The production forecast is based largely on data provided to the Inquiry by key producers in the east coast gas market and is split between ‘developed supply’ and ‘undeveloped supply’ depending on whether investment to develop reserves in particular fields has already been sanctioned.

Chart 1.1 Forecast gas supply and demand balance in the east coast gas market, excluding Arrow, 2016–25



Source: ACCC analysis based on data obtained during the Inquiry, AEMO’s 2015 *National Gas Forecasting Report* and EnergyQuest, *EnergyQuarterly*, March 2016.

Note: The top line aggregates AEMO’s ‘medium’ domestic demand forecast with LNG plant’s production capacity, while the second line aggregates the same domestic demand forecast with LNG export commitments. The three shaded areas represent the aggregated production forecasts of all the producers in the east coast gas market. The ‘developed supply’ forecast is based on all currently producing or sanctioned projects, while the ‘undeveloped supply’ forecasts are based on gas fields which have been identified as containing 2P reserves but not yet sanctioned for production.

Chart 1.1 shows that sufficient gas is currently forecast to be produced in the east coast gas market to meet the domestic demand and existing export contractual commitments in the medium term, even without gas from Arrow.²⁰ However, whether the timing and volumes of

19 2P (proved and probable) is a measure of gas reserves that are estimated, as at a given date, to be commercially viable to produce (that is, there is at least 50 per cent probability of recovering a volume equal to, or in excess of, the estimate). 2C (contingent) is a measure of gas resources estimated, as at a given date, to be potentially recoverable from known sources, but the project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

20 This analysis does not take into account any constraints within the east coast gas transmission or distribution systems which may create localised supply constraints at particular points in time. The analysis is also based on annual production forecasts, so does not account for seasonal variabilities in demand.

these forecasts will be realised is dependent on the development of undeveloped fields by the LNG projects and other producers in the east coast gas market. The timing of the production of this gas will ultimately depend on whether it is economic to invest in the development of these fields when they are required (discussed further in chapter 3). The majority of 2P reserves, including undeveloped reserves, are located in CSG fields in Queensland.²¹

Chart 1.1 does not include forecasts of production from contingent gas resources. The contingent resources consist of gas from conventional reservoirs, CSG and tight gas resources across a number of basins. These resources are considered to be more challenging to develop economically due to being technically difficult to extract, located remote from supporting infrastructure such as transmission pipelines and/or having high levels of inert gases or other contaminants that require construction of additional treatment facilities. The timing of development of these resources has been hindered by the low oil price, which has stifled exploration and appraisal investment by producers across the east coast gas market and made many of these contingent resources uneconomic to extract at this time.

If the economics of LNG warrant, the LNG projects may seek to sell LNG on international markets in excess of their existing contractual commitments to maximise the production of their LNG plants. Chart 1.1 shows that there is currently insufficient gas forecast to be produced in the east coast gas market to meet both the domestic demand and allow LNG projects to fully utilise their LNG plant capacity (the gap between the top demand line and ‘undeveloped supply—other producers’ area). This gap is influencing decisions made by gas producers on the east coast and resulting in domestic gas prices being influenced by LNG netback prices (discussed further in chapter 2).

A key source of future gas supply in the east coast gas market that could fill this gap is the Arrow Energy project, which has an estimated 8915 PJ of 2P CSG reserves in Queensland.²² In February 2016, BG and Shell completed a merger²³, which may create a clearer path for Arrow gas reserves to market. While at the time of writing there had not been any announcements regarding the future development of Arrow reserves, the Inquiry expects that the majority of Arrow’s reserves are likely to be committed to LNG exports to justify their development. Another potential source of future supply could be gas from the Northern Territory delivered via the planned Northern Gas Pipeline (NGP).²⁴

While gas producers will respond to the price signals in the long run, the medium-term supply outlook for the east coast gas market remains uncertain in the current economic environment (discussed further in chapter 3).

1.1.2 The LNG projects have changed historical gas flows in the east coast gas market

The LNG projects are not offering significant additional firm supply to domestic users in Queensland

Historically, some of the LNG joint venture parties were major suppliers to Queensland’s domestic gas market. However, once investment decisions were taken and construction commenced, the LNG joint venture parties shifted their focus to ensuring a smooth transition to LNG production. Some LNG projects gave evidence to the Inquiry that while they will continue to meet their existing domestic commitments, they did not expect to be in a position to consider significant additional firm supplies to domestic users until their LNG production stabilised and plateaued. This will give the LNG projects time to better understand their actual well production and decline rates and the productive potential of their undeveloped reserves.

However, once production plateaus, the LNG producers will have economic incentives to maximise the value of any gas they produce in excess of their existing LNG export commitments. The LNG projects are likely to seek to sell this gas to the highest value user, which could be either

21 Approximately 90 per cent of 2P gas reserves estimated in the east coast gas market as at February 2016 were made up of CSG—EnergyQuest, *EnergyQuarterly*, March 2016, table 17.

22 EnergyQuest, *EnergyQuarterly*, March 2016, table 14.

23 See ACCC merger register: <http://registers.accc.gov.au/content/index.phtml/itemId/1190874/fromItemId/751043>.

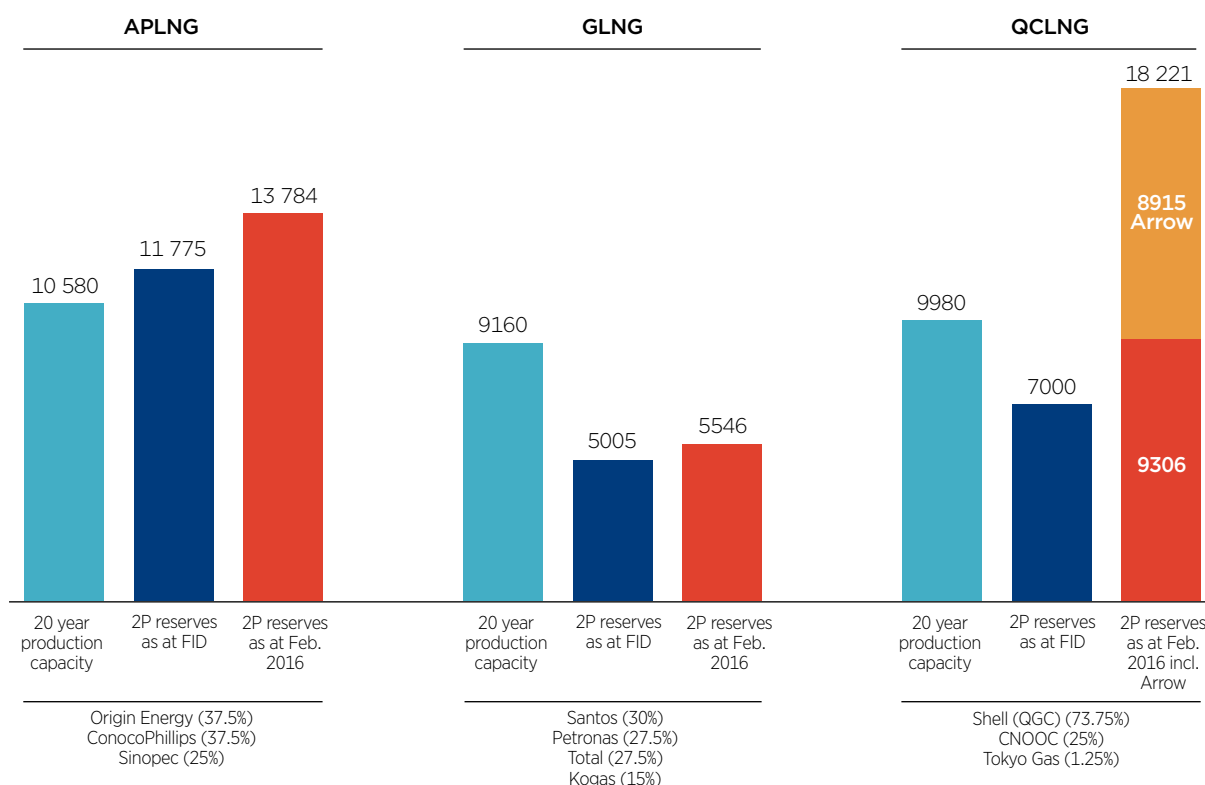
24 This planned pipeline was previously referred to as the North East Gas Interconnector.

domestic users or international LNG spot buyers. Low LNG spot prices would potentially make domestic supply more attractive.

Production from the Cooper Basin has been re-directed to Queensland

At the time the three LNG projects were sanctioned, the extent to which they expected to rely on reserves owned by them to meet their contractual export commitments varied. APLNG and QCLNG primarily expected to meet their LNG needs through development of resources owned by them. By contrast, GLNG always expected to source gas from other producers in the east coast gas market to supplement its CSG reserves.²⁵ This is reflected in chart 1.2, which shows that the total production capacity of the two GLNG trains significantly exceeded the volume of gas that GLNG could produce from its 2P CSG reserves at the time the project was sanctioned.

Chart 1.2: Expected LNG plant production capacity and 2P CSG reserves of the LNG projects



Note: Numbers are in PJ.

Sources: Production capacity estimates are based on publicly announced LNG plant nameplate capacity converted into PJs plus fuel gas (estimated at 8 per cent of capacity); 2P reserves as at February 2016 are sourced from EnergyQuest, *EnergyQuarterly*, March 2016, table 14; Origin's ASX announcement, 'Australia Pacific LNG: Final Investment Decision', 28 July 2011; Santos' media release 'GLNG project sanctioned—Final investment decision on US\$16 billion 2-train 7.8 mtpa project', 13 January 2011; BG Group's media release, 'BG Group sanctions Queensland Curtis LNG project', 31 October 2010.

All three LNG projects expect to increase the size of their 2P reserves over time through reserve optimisation and further exploration and appraisal activities. While the 2P reserves of the three LNG projects have grown over the past five years, the 2P reserves of GLNG are still well short of the volume required to fully maximise the production capacity of its two trains. To meet this shortfall, GLNG has purchased substantial volumes of gas over the past few years from a range of gas suppliers in the east coast gas market (table 1.2). QCLNG has also announced that it has purchased some gas from third parties.

²⁵ Santos' media release, 'Santos to supply 750PJ of portfolio gas to GLNG', 25 October 2010.

Table 1.2: Publicly announced domestic gas purchases by the LNG projects, 2010-15

Date announced	Seller	Buyer	Quantity (PJ)	Commences	Term (years)
Oct-10	Santos	GLNG	750	2014	15
May-12	Origin	GLNG	365	2015	10
Oct-12	Origin SG and Combabula	GLNG	355	2015	30
Nov-13	Origin	QCLNG	30	2014	2
Dec-13	Origin	GLNG	100-194	2016	5
Mar-14	WestSide	GLNG	445	2015	20
Q2 2014	Other	GLNG	25	2015	7
Q2 2014	Other	GLNG	60	2016	21 months
Sep-15	Senex	GLNG	260-360	2018	20
Dec-15	AGL	GLNG	254	2017	11

Source: EnergyQuest, *EnergyQuarterly March 2016*, table 3 and Santos' media release, 'GLNG signs gas purchase agreement with AGL', 24 December 2015.

Critically, a significant portion of this gas has come from the Cooper Basin. Gas from the Cooper Basin was historically an important source of supply for the South Australian market via the Moomba to Adelaide Pipeline System (MAPs), and for the New South Wales market via the Moomba to Sydney Pipeline (MSP). Redirection of gas from the Cooper Basin to Queensland has reduced diversity of supply available in the southern states, adversely affecting the competitive dynamics in those states (discussed in chapter 2).

There have been concerns among some market participants that LNG export agreements may contain strict gas delivery conditions, including penalty clauses for failure to meet LNG supply commitments, which would dictate the decisions of the LNG joint venture parties. The Inquiry did not identify any such clauses. Nevertheless, the risk of damaging their international reputation as a dependable LNG supplier and the threat of GSA termination under certain non-compliance situations provide major incentives for LNG joint venture parties to meet their contractual export commitments, even in a low oil price environment.

1.2 The gas market will not be the same for industrial gas users

The domestic gas market on the east coast was historically characterised by long-term GSAs and gas buyers typically had few difficulties renegotiating their GSAs when they expired. Gas supplied to industrial users under long-term GSAs was historically priced using a cost-plus formula, in which the contract price paid for gas by users was calculated based on the cost of production plus a margin, and escalated with inflation. Non-price terms such as the duration of GSAs, price review mechanisms, quantities (including flexibility on delivered quantities) and delivery locations were typically rolled over from one GSA to another and remained relatively stable. However, the introduction of the LNG significantly altered the contracting landscape in the east coast gas market.

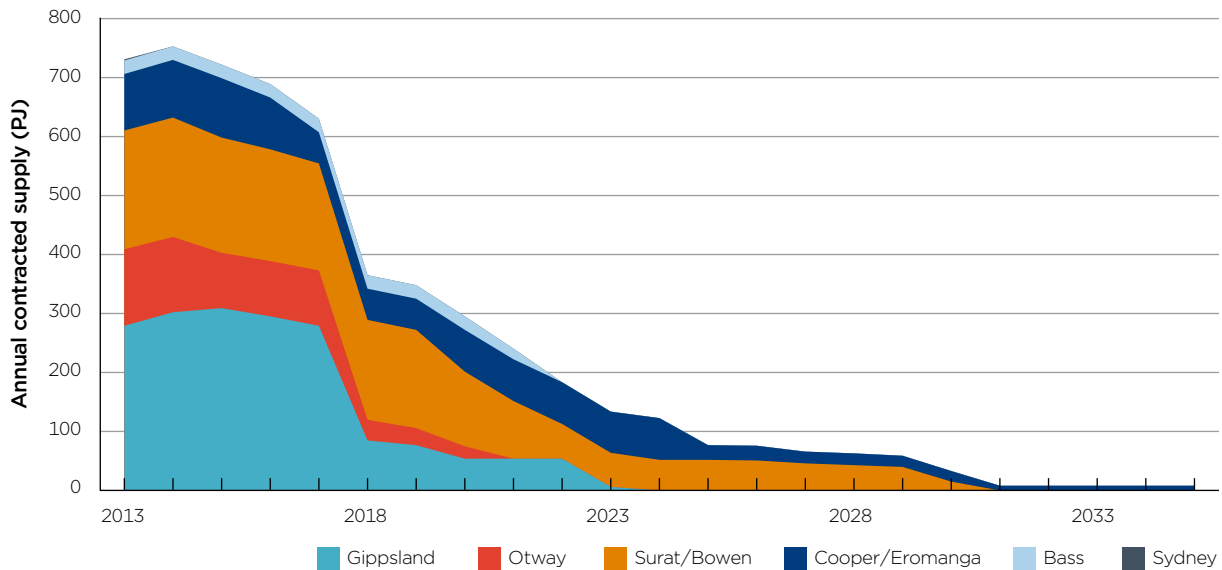
1.2.1 Initial re-contracting difficulties and conflicting communication from gas suppliers amplified uncertainties for industrial gas users

Previous inquiries into the supply of wholesale gas in the east coast gas market received conflicting reports from gas suppliers and industrial gas users about prevailing supply and demand conditions, the extent of active gas supply negotiations and the supply outcomes. It was difficult for these inquiries and government policy makers more broadly to assess competing claims about these matters as critical information relating to GSAs and contractual negotiations was unavailable due to confidentiality restrictions.

The Inquiry used the ACCC's compulsory information gathering powers to overcome these restrictions and gain an insight into supplier-user interaction over the past few years. The Inquiry found that in the period from about 2012 to the end of 2014 the domestic users in the east coast gas market entered a recontracting phase as many long-term legacy domestic GSAs were due

to expire over the coming years (chart 1.3). A large number of industrial gas users approached gas retailers and producers that historically supplied the domestic market seeking gas supply for various years from 2016.

Chart 1.3: Gas volumes under domestic GSAs for supply from 2013, as at November 2014, by basin



Source: Core Energy, *Eastern Australian Gas Outlook 2035*, 2014, p. 5.

The evidence obtained by the Inquiry has confirmed that over the period from about 2012 through to the end of 2014, a number of industrial users encountered difficulties in securing gas for supply in 2016 and beyond. They found that they had fewer options for gas supply than previously. Some gas suppliers declined to make any offers for supply in the requested period, while others indicated that they could only supply gas for particular years, rather than the entire period. Where offers had been made, they were largely at higher prices and on less flexible terms than in the past. The scarcity of offers for gas supply made it difficult for industrial users to assess whether the prices they had been offered were competitive and fuelled their uncertainty about the future availability of gas.

In addition, a number of industrial users gave evidence that they observed a change in the attitude and behaviour of some gas suppliers. These included some sellers not responding to approaches made by users in a timely manner, drawing out negotiations, not following up on offers to buyers or otherwise making completion of the negotiations very difficult. In one instance, after several months of negotiations, a seller decided to increase the price at the last moment when a GSA was close to execution. On another occasion, a buyer was given an unreasonably short period of time to respond to an offer, preventing them from following due diligence within their company that would have been necessary to accept the offer.

The Inquiry found that the willingness or ability of the LNG projects, gas producers and key retailers to make gas offers in the period from about 2012 to the end of 2014 was hindered by the broad market uncertainties associated with the start-up of the LNG plants, uncertainties associated with future gas outlook and future domestic prices as well as other factors specific to individual suppliers. The LNG projects generally declined to offer significant additional firm supply commitments to domestic users to concentrate on securing gas to meet the LNG plant start-up timeframes. Some producers were fully contracted for certain years as a result of their existing commitments to the LNG projects or other parties. The retailers generally had sufficient volumes of gas to sell for 2016 and 2017, but some of the retailers had difficulties in making offers of supply for this gas due to impending price reviews in their own GSAs with gas producers. Some retailers were also in the market themselves seeking to purchase gas for re-supply post 2018.

The evidence given by both industrial users and gas suppliers confirms that there was a difficult contracting period from about 2012 to the end of 2014 for all market participants. The Inquiry

did not find evidence of gas suppliers hoarding gas. Instead, the evidence suggests that gas suppliers were reacting to rapidly changing commercial dynamics in an uncertain environment.

However, the Inquiry found that in the periods when particular suppliers were not active in the market, they were often not transparent with industrial users about the reasons for their limited engagement. At the same time, these suppliers were sensitive about public perceptions and were keen to demonstrate their participation in the market via offers or executed agreements. Gas suppliers or their representative bodies made public statements about the state of the contracting market which made no references to the challenges experienced by market participants and instead portrayed the market as functioning well.

For example, on 3 January 2014, The Australian Petroleum and Exploration Association (APPEA) issued a media release stating:

In relation to the recommendation for an industry-led initiative to provide more 'information' to the market, APPEA notes the gas market already has abundant information available to it. The range of gas supply agreements that have been struck over the last 12 months suggests that there is enough information available to allow supply contracts to be concluded between willing buyers and sellers.²⁶

This statement was followed by a list of agreements for gas supply, reproduced in other public statements. However, only a handful of agreements on this list were between the established key gas suppliers and industrial users. The majority of listed agreements were between producers and either the LNG joint venture parties, retailers or other producers. Some also involved agreements entered into by junior explorers for the potential supply of gas from projects that had not yet been sanctioned. Further, the Inquiry found evidence that some supplier behaviour, including their approach to individual offers of supply, was motivated at least in part by the likely public perception of their actions.

In an opaque, changing and uncertain market, the nature of these communications amplified the concerns and uncertainties of industrial users, making it increasingly difficult for them to make informed business decisions.

1.2.2 Domestic gas prices are now higher and more volatile due to the influence of international LNG and oil prices

Domestic market participants are now exposed to international LNG and oil prices

All the participants in the east coast gas market are now exposed to international LNG and oil prices. The LNG joint venture parties sell LNG on international markets and are directly exposed to international LNG prices. The LNG joint venture parties are also directly exposed to the world oil prices through their export GSAs. Each of the LNG projects was underpinned by large foundation export GSAs with buyers from China, Japan, Malaysia and Korea to underwrite their lumpy, high cost and risky investments. The LNG prices under these GSAs are set at a percentage of the Japanese Customs-Cleared Crude (JCC) price, which closely tracks other major oil indexes (Brent Crude, West Texas Intermediate, Tapis etc.).²⁷

By introducing the export option, the LNG projects have exposed domestic market participants to international LNG prices. The international LNG prices now influence the domestic gas prices through LNG netback prices, which are calculated by subtracting the cost of shipping, liquefaction and transmission from the spot or contract LNG prices. The LNG netback prices are becoming important indicative prices for some domestic users, particularly in Queensland. This is likely to remain a feature of the domestic gas market into the future, and has some benefits in the long term, as LNG prices are achieved in a competitive international market and the calculation of the LNG netback price is relatively transparent (discussed further in chapters 2 and 5).

²⁶ APPEA's media release, 'Study shows gas market is delivering for all Australians', 3 January 2014.

²⁷ JCC is a monthly volume-weighted average price of Japanese oil imports published by the Japanese Government.

The purchases by the LNG projects are all oil-linked, directly exposing the suppliers of gas to oil prices. Some non-LNG producers in the east coast gas market have also introduced oil-linked pricing in GSAs with domestic gas retailers or other producers (refer to box 1.2 for an explanation of how oil-linking works). These producers have expressed a preference for commodity-based reference pricing and consider that oil indexation is appropriate given its link to LNG prices and new LNG-driven market dynamics in the east coast gas market. The presence of oil-linked mechanisms in GSAs means that the prices paid by the gas buyers under those GSAs will adjust quite rapidly in response to the changing oil prices.

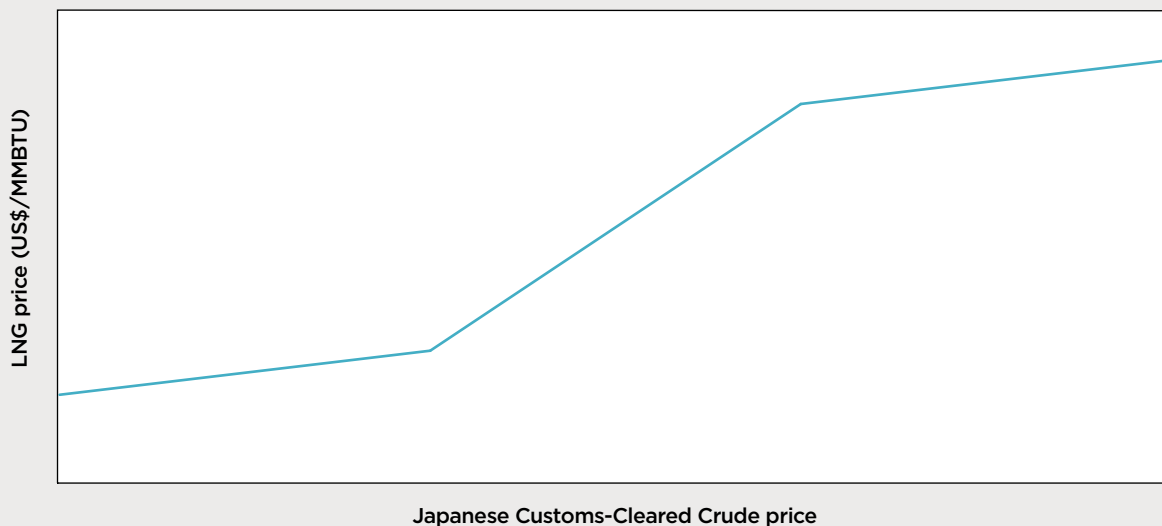
Whereas certain producers also appear to be keen to introduce oil-linked terms into their GSAs with industrial users, the Inquiry has only found a couple of such agreements. Further, the Inquiry has found that the retailers do not appear to be introducing oil-linked terms into their GSAs with industrial users. While a number of domestic users expressed concerns during the Inquiry about the increased prevalence of gas supply offers based on an oil-linked pricing mechanism, the prices in GSAs of the vast majority of domestic industrial users continue to be based on fixed formulas. This provides greater certainty of prices to industrial users over the term of the GSA (except to the extent that the GSA is subject to a price review).

However, the prices paid by domestic industrial users under long-term GSAs are nevertheless influenced by oil prices and will adjust to reflect those prices during GSA price reviews or at the re-contracting stage. This is because the domestic prices are now influenced by the LNG prices, which are in turn influenced by the oil prices.

Box 1.2: Oil-linked pricing in export and domestic GSAs

LNG price s-curve

Internationally, GSAs for the supply of LNG typically set the price of LNG at a percentage of the JCC, which is often referred to as the *slope*. The slope is typically between 13 to 15 per cent of the JCC and gives the price of LNG in US\$/MMBTU, which for Australian exporters would then be converted to AU\$/GJ. The slope is often reduced at high and low oil prices to limit the financial exposure of buyers and sellers, respectively, in which case it is known as the s-curve. The GSA price may also contain a fixed commodity component.



As a simplified example, if the JCC price for a particular month is US\$50/barrel and a GSA's slope is 14 per cent, the price of LNG = $0.14 \times 50 = \text{US}\$7/\text{MMBTU}$. At an exchange rate of AU\$1 = US\$0.75 and using 1 MMBTU = 1.055 GJ, this equates to AU\$8.85/GJ.

In the east coast gas market, some oil-linked domestic GSAs have price formulas that are 100 per cent oil-linked and some have a combination of an oil-linked component and a commodity gas component indexed to inflation. Oil indexing is often based on Brent Crude or JCC prices with percentages of 5 to 8 per cent, depending on the oil-linked weighting. The oil-linked component often gives prices in US\$, which adds exchange rate risk for the buyer.

The following is a simplified example of a pricing formula with oil-linked (75 per cent weighting) and commodity (25 per cent weighting) components. Currency and unit of energy conversion are not included in this example.

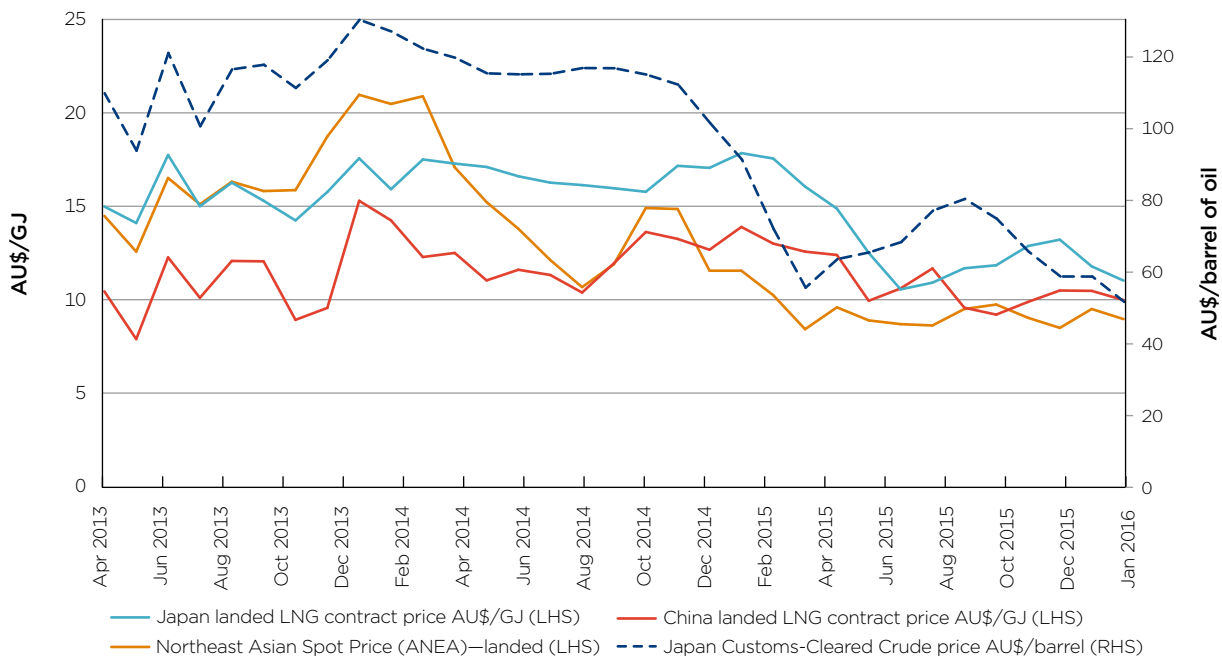
Gas price/GJ = 0.75 (7 per cent x Brent Crude price) + 0.25 (inflation x commodity gas price)

LNG and oil prices are volatile

LNG and oil prices can fluctuate dramatically in response to changes in the supply-demand balance of the commodity as well as changes in broader international economic activity. Chart 1.4 shows average monthly GSA prices for LNG delivered to Japan and China, average monthly spot prices for LNG delivered to Northeast Asia and average monthly JCC prices over the past few years.²⁸

²⁸ These prices are based on supplies from a number of LNG exporting countries, not just Australia.

Chart 1.4: Average monthly prices: LNG GSA prices to Japan and China, Northeast Asian spot prices and JCC, April 2013–January 2016



Source: Argus Media.

Note: Exchange rate data from the Reserve Bank of Australia was used to convert prices from US\$/GJ to AU\$/GJ.

Chart 1.4 shows that monthly average LNG GSA prices reached nearly AU\$18/GJ delivered to Japan and just over AU\$15/GJ delivered to China but dropped to \$11–12/GJ delivered to Japan and \$8/GJ delivered to China by early 2016. These prices were roughly in parallel with oil prices but were also influenced by the AU\$/US\$ exchange rate.

The wholesale gas prices paid by gas users in LNG destination countries will be higher than the LNG prices shown in the chart. Regasification terminal costs²⁹, pipeline transportation costs within the destination country and the LNG shipper’s operating costs and margin would need to be added to the LNG price to get an idea of the likely delivered price a wholesale gas buyer would pay in the destination country.

Domestic gas prices are now higher and more volatile than in the past

The Inquiry obtained data on gas prices paid by gas buyers under existing GSAs for firm supply of gas for at least three months and for a volume of at least one PJ. Table 1.3 shows the volume weighted average gas prices paid by these buyers in 2015. These prices are for gas that has already been processed but do not include the cost of transportation. Indicative pipeline transportation charges are also shown in table 1.3 to give an idea of the average delivered gas prices to the major demand centres each basin supplies.

²⁹ A regasification terminal is where LNG ships dock in the destination country and LNG is converted from liquid to gas.

Table 1.3 Volume weighted average wholesale gas prices paid in Q1 2015, by basin

Basin	Volume weighted average wholesale gas price at the basin (\$/GJ)	Indicative pipeline transportation charges to major demand centres ³⁰ (\$/GJ)
Cooper	5.11	Moomba to Brisbane ³¹ \$1.59–\$2.31 Moomba to Adelaide \$0.64–\$0.68.
Gippsland, Otway and Bass	4.30	Longford to Sydney \$1.00–\$1.28 Longford to Melbourne \$0.37 Port Campbell to Melbourne \$0.36 Otway to Adelaide \$0.59–\$0.63
Surat and Bowen	4.15	Wallumbilla to Gladstone \$0.71–\$1.23 ³² Roma to Brisbane \$0.43–\$0.95
All basins combined	4.44	–

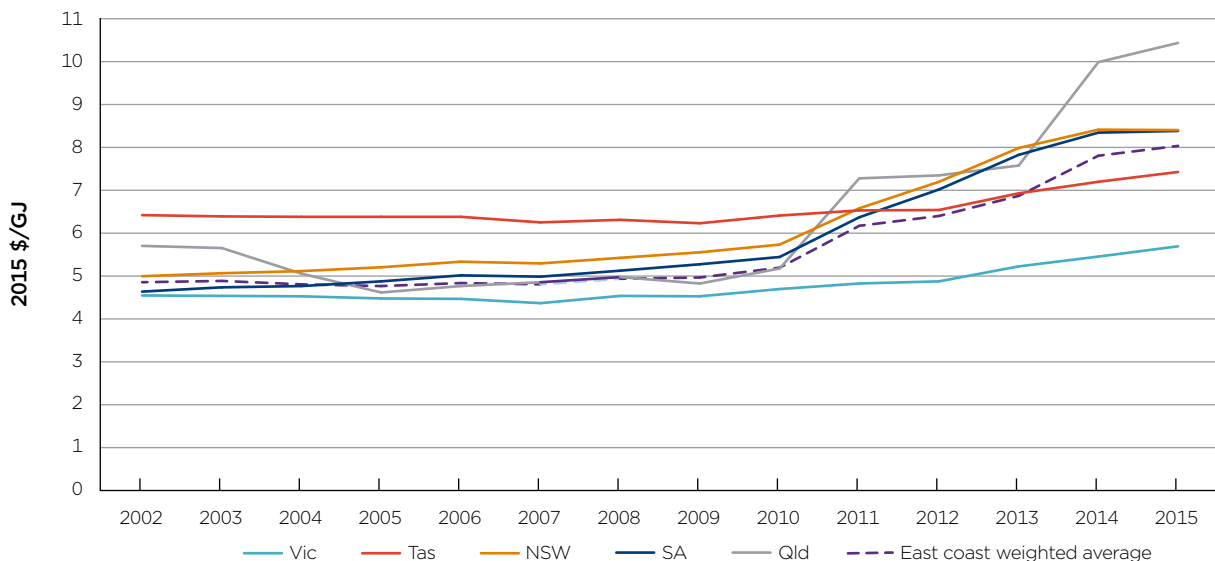
Source: ACCC analysis based on data obtained during the Inquiry.

Note: The prices in this table are exclusive of GST. They are based on amounts actually paid by gas users to gas producers in the first quarter of 2015. Prices paid under bilateral GSAs reflect, amongst other things, the specific non-price terms and conditions agreed between the parties. The prices in this table do not take into account the variations in non-price terms and conditions between the GSAs.

While the prices set out in table 1.3 reflect the average volume weighted prices actually paid by domestic users in 2015, they are predominantly based on legacy long-term GSAs and therefore are heavily influenced by prices that had been agreed in the past (although prices under a number of these GSAs have been varied following price reviews). Many of the GSAs that had been executed recently are for supply from 2016 and are therefore not reflected in the table.

Chart 1.5 shows average delivered gas prices paid by users in each major demand centre taking into account only GSAs that are entered into in a particular year.³³

Chart 1.5: Average delivered wholesale gas prices in new GSAs for large industrial users



Source: Oakley Greenwood, *Gas Price Trends Review*, December 2015.

Note: This chart only includes GSAs with a total contract volume of at least one PJ.

Chart 1.5 shows that significant price increases have occurred in the past five years in every state, to varying degrees, and have been particularly pronounced in Queensland. Evidence obtained by the Inquiry generally supports these trends. The Inquiry found that delivered gas prices under some domestic GSAs with fixed pricing mechanisms executed recently are as high

³⁰ The transportation charges in this table have been calculated assuming the shipper transports its maximum daily quantity every day of the year (that is, load factor of 100 per cent). If the shipper transports less, the average cost per GJ will be higher.

³¹ Moomba to Brisbane tariff is the sum of tariffs for the South West Queensland Pipeline and the Roma to Brisbane Pipeline.

³² The quoted pipeline tariffs are for Queensland Gas Pipeline.

³³ The transportation costs in chart 1.5 include only real firm forward haul transport costs. Oakley Greenwood indicated that in 2015 transportation costs averaged 10 per cent of wholesale gas prices and gave the following breakdown: Victoria 7 per cent, Queensland 10 per cent, New South Wales 13 per cent, South Australia 19 per cent and Tasmania 29 per cent.

as \$11-12/GJ. Some users raised concerns in the course of the Inquiry that domestic prices in the east coast gas market were now higher than gas prices paid by overseas users purchasing LNG on international markets. The evidence obtained by the Inquiry does not support these claims—domestic gas prices in the east coast gas market are still generally lower than prices paid by overseas users that purchase LNG.

Exposure to international LNG and oil prices has increased not only the level, but also the volatility of domestic gas prices in the east coast gas market. Price volatility is now a feature of all GSAs that have an oil-linked pricing mechanism. Table 1.4 shows indicative prices that domestic buyers would pay in 2018, at given foreign exchange and oil price assumptions, based on a sample of domestic oil-linked GSAs that have been executed in the past few years. These prices are for gas that has already been processed but do not include the cost of transportation. As shown in the table, prices under oil-linked GSAs could vary by as much as \$5/GJ depending on the price of oil.

Table 1.4 Indicative prices that will be paid in 2018 under a sample of recently executed oil-linked domestic GSAs

Brent Crude (US\$/barrel)	\$30	\$50	\$80	\$100
Indicative prices (AU\$/GJ)	\$3.20-\$5.10	\$4.50-\$6.60	\$6.50-\$8.90	\$7.80-\$10.40

Source: ACCC analysis based on data obtained during the Inquiry.

Note: The indicative price ranges were estimated using US\$/AU\$ exchange rate of \$0.71. Brent Crude oil prices are used because all the contracts in the sample contain pricing mechanisms linked to Brent Crude.

Price volatility affects all gas buyers in the market, not just those with oil-linked GSAs. It is now more difficult for industrial gas users to predict what the domestic gas prices will be in the future when their current GSA expires. These increased price risks are exacerbated by an uncertain supply environment and a lack of price transparency and information asymmetry between gas suppliers and gas buyers. This provides a distinct bargaining advantage for large producers and retailers in their negotiations with industrial gas users.

While price volatility is often observed in many other commodity markets, it is a new pricing dynamic for industrial gas users in the east coast gas market. Over time, other commodity markets have developed mechanisms to assist market participants to manage price and supply risks (for example, derivatives, financial products etc.). Such mechanisms are currently limited in the east coast gas market. This creates the potential for inefficient pricing outcomes that could lead to inefficient investment decisions being made both by industrial users and gas producers. Therefore, there is a case for introducing measures to facilitate growth in liquidity in the trading markets and to improve availability and transparency of pricing information to assist market participants to adjust to the new pricing dynamics (discussed further in chapters 4 and 5).

1.2.3 Industrial users are responding to increasing input costs and risks caused by rising domestic gas prices

Rising domestic gas prices have had a noticeable effect on the input costs of some industrial gas users. Gas is a major input for some industries and is used to generate heat in industrial processes such as brick manufacturing, and as a feedstock for some chemical production processes, such as fertiliser, plastics and methanol. Indicative figures include 15 per cent of inputs costs for bricks and roof tiles, 25 per cent for cement and alumina, 40 per cent for fertilisers³⁴ and up to 80 per cent for ammonia.³⁵ Rising domestic gas prices affect the international competitiveness of industrial users, which are exposed to global markets, including plastic manufacturers and methanol producers.

It is technically possible for some manufacturers that use gas as a source of energy or as a chemical feedstock to switch to an alternative. For example, liquefied petroleum gas can be used for ammonia production and coal can be used for methanol production. However, some industrial users have given evidence that switching would require replacing a major piece of plant and the cost of this would be commercially unviable. Further, some manufacturing, such as

³⁴ Manufacturing Australia, *Impact of gas shortage on Australian manufacturing: May 2013*.

³⁵ Incitec Pivot’s public submission to the Inquiry.

glass, requires very high temperatures and alternatives such as electricity are either prohibitively expensive per unit of energy or cannot effectively supply the required temperature.

Some industrial users have given evidence that they were able to reduce their gas use, for example, by running plants below peak capacity or deferring plans to increase production. However, some have said that this has had an impact on the overall efficiency of operating certain plants.

Higher domestic gas prices and increased price volatility are putting industrial users under greater pressure to manage their gas costs and increase their need for greater flexibility, which is becoming harder and more expensive to obtain. In the face of this uncertainty, industrial users find it harder to make decisions about the future viability of their businesses and about future investment decisions. There are currently few effective financial instruments, such as hedge contracts, designed specifically for the east coast gas market that can be used by market participants to manage price risks. Some industrial users are becoming increasingly reliant on market mechanisms (with their own inherent risks) to manage increased gas price risks.

Some industrial users are changing their approach to sourcing gas to adapt to the changing market. A number of users are now taking a portfolio approach to gas contracting. Instead of relying on a single large firm GSA, they entered into a range of smaller GSAs with several suppliers and on different terms. This has given them additional overall flexibility that was more costly to obtain in a single GSA. However, this approach is a significant change from previous contracting practices. The extent to which this approach will reduce the gas supply risks faced by the industrial users will depend on a number of factors, including the depth and liquidity of the market. The portfolio approach has also increased the transaction costs of the industrial users in negotiating and managing multiple GSAs.

A number of industrial users are now using the short term trading markets (STTMs) in Sydney, Adelaide and Brisbane as well as the Victorian Domestic Wholesale Gas Market (DWGM) to supplement their gas needs. These users often engaged a service provider to help them trade in the STTMs. Participation in the STTMs and the DWGM allows users to reduce their overall cost of gas through opportunistic purchases of relatively cheap gas in periods when excess gas is available in the market. While some industrial users are using the STTMs and the DWGM to manage gas price risks, the extent to which they can rely on these mechanisms to manage price risks is currently limited (further discussed in chapter 4).

Several industrial users took a direct interest in the development of new gas resources to manage their supply risk (box 1.3). However, this has exposed them to risks associated with upstream gas production which they had not been previously exposed to.

Box 1.3: New funding models for gas development—Strike Energy

Strike Energy (Strike) is an independent oil and gas company listed on the Australian Stock Exchange. Strike's primary focus is the commercialisation of gas resources within its Southern Cooper Basin Gas Project in South Australia (operated by Strike with a 33.3 per cent interest from Energy World Corporation). Strike is currently undertaking appraisal and development work on the projects aimed at proving its commercial viability in advance of moving to final investment decision and scaling up production.

In order to finance development of the gas project, Strike has signed a number of agreements to supply gas to industrial gas users, including Orora Limited for 30 PJ over 10 years, Austral Bricks for 12.5 PJ over 10 years and Orica Australia Pty Ltd for up to 150 PJ over 20 years.³⁶ These agreements include provisions for milestone payments or option fees when reaching specific decision points (for example, proceeding to a pilot production test project). Orica made its first pre-payment in May 2015. These agreements were signed during the period from about 2012 to the end of 2014 when few offers were being made for the supply of gas.

While these agreements provide an advantage to gas users in potentially accessing gas supplies over a substantial period of time, it also puts gas users into an unfamiliar risk environment. While Strike continues to make progress, the process of obtaining supply from the Southern Cooper Basin Gas Project is challenging.

There have been similar attempts in the past by users in Western Australia to get involved in upstream gas production. Alcoa has utilised a number of strategies to develop gas resources including the Red Gully gas project (in 2013) and with companies Transerv Energy (in 2008) and Buru Energy (in 2007 with then Arc Energy). While the Red Gully Project is currently in production and Transerv Energy is continuing attempts to unlock the Warro gas field, it is yet to produce commercial quantities of gas. In 2015, Alcoa withdrew from the Buru agreement as it had secured alternative gas supplies to power its Western Australian refineries.

1.2.4 The gas market is settling down, but supply uncertainty remains for industrial users

More gas became available to industrial gas users throughout 2015 as some of the factors that contributed to the scarcity of supply offers during the period from about 2012 to the end of 2014 were resolved. Most industrial gas users appear to have been able to finalise contractual negotiations for the supply of gas for 2016 and 2017. However, industrial users continue to face uncertainty about the likely future domestic prices and gas availability.

Low oil prices are creating uncertainty as to whether producers will make timely investment into development of undeveloped reserves to continue meeting the demand of the LNG projects and domestic users (discussed further in chapter 3). There is also uncertainty on when and to what extent the LNG projects will start making firm offers for supply of gas to domestic users once they reach steady production state. The Inquiry notes that on 31 March 2016, Incitec Pivot Limited announced that it has entered into a new firm gas supply agreement with QGC.³⁷

There is uncertainty about the role that retailers will play in the future in supplying domestic industrial users. While all key retailers have now secured gas from the GBJV for re-supply to domestic users in the southern states, it is unclear whether or to what extent they all intend to maintain their current large industrial customer base. For example, AGL announced that it has acquired supply over 2018–20 for its 'residential and small business gas customers'.³⁸ The Inquiry understands, however, that the GBJV is currently making direct offers to industrial customers for supply in this time period.

³⁶ Strike's ASX announcement, Strike signs new gas supply option agreement, 15 January 2014.

³⁷ Incitec Pivot's ASX announcement, 'IPL announces interim gas supply arrangements for Phosphate Hill Fertiliser Manufacturing Plant', 31 March 2016.

³⁸ AGL's media release, 'AGL secures gas supply until 2020 with Bass Strait agreement', 9 April 2015.

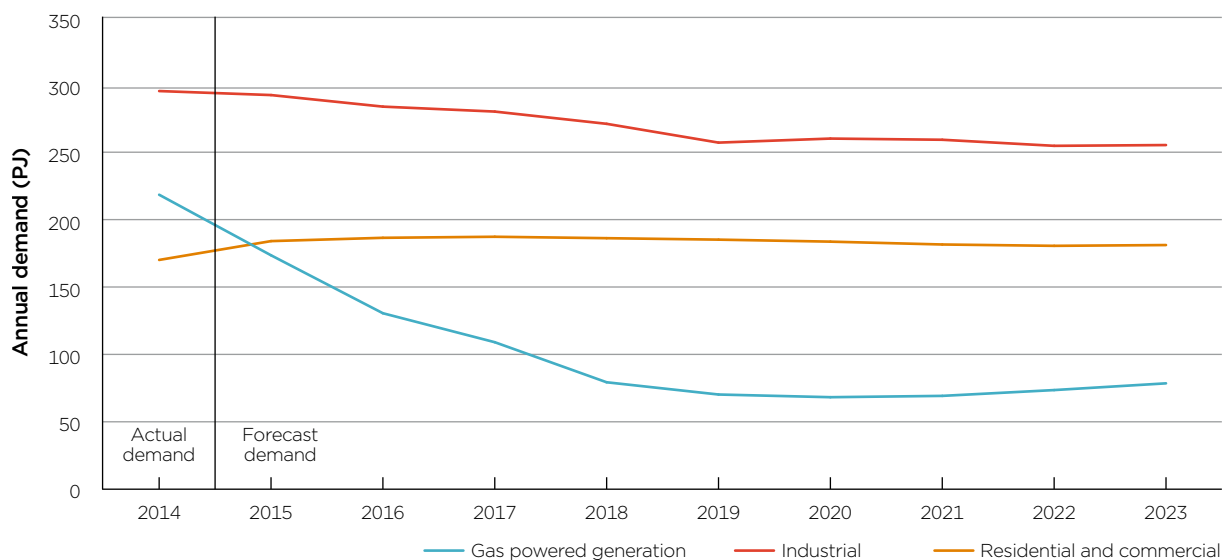
Further, there is uncertainty as to what extent the investment decisions by all producers in the market, particularly in Queensland and the Cooper Basin, will be driven by opportunities presented by LNG rather than the needs of the domestic market. There appear to be a number of key reasons why supplying the LNG projects may often be more attractive than supplying domestic users. The LNG projects have significant scale advantages and can enter into large long-term commitments. They potentially have higher willingness to pay for gas, particularly when international LNG prices are high. They typically have a flat demand profile and are not exposed to season variability.

Given the impact of moratoria and other regulatory impediments in New South Wales and Victoria on gas development, there is a possibility that industrial users in the southern states will have to increase their reliance on gas supply from basins that are located further away from them. This exacerbates uncertainty for those users about future gas availability.

In an environment characterised by high and volatile prices, suppliers may also perceive industrial users as more risky customers. The Inquiry found that in considering making offers for supply of gas, some suppliers were concerned about the effect of rising gas prices on the continuing future viability of international trade-exposed, gas intensive industries which faced competition from imports. By contrast, the LNG projects are highly expensive long-term projects, which are not as sensitive to price fluctuations.

The changed pricing dynamics and prevailing uncertainties in the east coast gas market are expected to further depress domestic demand in the short to medium term, particularly in gas powered generation (chart 1.6).

Chart 1.6 Actual and forecast domestic demand, 2014-23



Source: AEMO's 2015 National Gas Forecasting Report.

To assist industrial users in such an uncertain environment, it is particularly important to make accurate and consistent information on gas reserves and resources available to enable them to make informed and efficient decisions on consumption and contracting strategies. However, there is currently a lack of consistent and adequate information readily available in the east coast gas market. In particular, gas reserves and resources are reported in an adhoc manner with differing requirements between jurisdictions. There are inconsistent requirements for companies reporting to the ASX and for companies not listed in Australia. Even where the reserves or resources are reported, they are not always easy to accurately interpret because the assumptions and fundamentals that underpin their calculations are opaque or unknown (discussed further in chapter 5).

1.3 LNG has accelerated the growth and development of the gas industry

1.3.1 Access to higher international prices has accelerated development of gas reserves and elevated the long-run marginal cost of supply in the east coast gas market

The size of the domestic demand in the east coast gas market and historic domestic prices were insufficient to justify development of the bulk of CSG resources in the short- to medium-term. The construction of the LNG facilities has allowed the LNG joint venture parties to connect their CSG resources in Queensland with international demand, which was a much larger market and placed a higher value on gas than domestic users. This has significantly increased the value of CSG reserves and accelerated their development in Queensland.

By leaving LNG trains with production capacity above contract volumes, the LNG projects have created opportunities for other producers in the east coast gas market to sell substantial volumes of gas for export at attractive prices. This has encouraged exploration and appraisal of other unconventional reserves in the east coast gas market, for example, in the Cooper Basin. While further investment into exploration and appraisal has been slowed by the falling oil prices, this has the potential to increase again once the oil price improves.

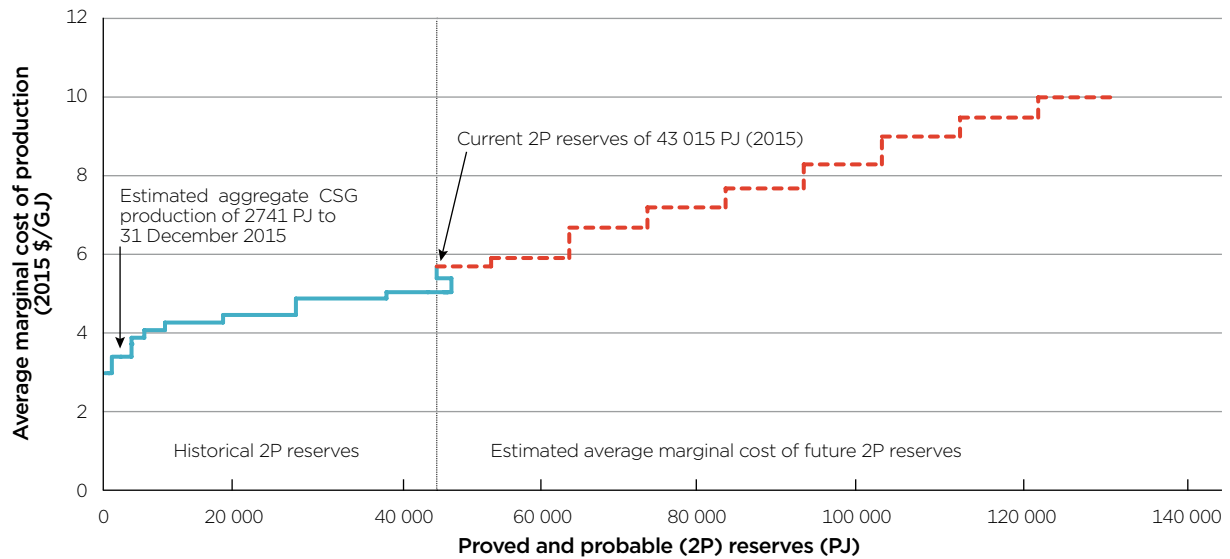
However, acceleration of reserve development is likely to move the cost of production along the cost curve more quickly than it otherwise would have as the most productive reserves are exhausted and more expensive to develop reserves are brought into production.

As shown earlier in table 1.1, the majority of the current 2P reserves and 2C resources on the east coast consist of CSG. Chart 1.7 shows the historical and projected average marginal cost of production of CSG in the east coast gas market in real terms. These cost estimates include drilling, well completion, gas processing, water treatment and compression. Chart 1.7 shows average marginal costs have increased from \$2.97/GJ when CSG production commenced in 1997 to around \$3.70/GJ for current production in 2015 and are projected to increase to around \$5.70/GJ when aggregate production reaches current 2P reserves of 43 000 PJ (all values in real \$2015).

Rising production costs are due to production moving away from areas of high production to areas where the coal seams have less favourable characteristics, such as lower permeability, which require more expensive drilling techniques or additional wells. These increasing costs are being significantly moderated by reductions in production costs and cost optimisation. Optimisation has occurred and is expected to continue through the LNG projects sharing and rationalising some facilities such as water treatment plants and pipelines, which defers or avoids some capital expenditure. They have also coordinated some production and entered into gas swaps to make production more efficient. Labour costs have reduced as the previously tight labour market has eased. Drilling efficiency has improved and new techniques have reduced the time and resources needed to drill each well.

The estimates in chart 1.7 allow for cost reductions as a result of production optimisation. However, there are significant uncertainties associated with estimating marginal cost of future reserves. Therefore, even though the production costs are projected to rise, this could change if gas producers achieve significantly greater cost savings over time than currently projected.

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



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

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

1.3.2 The gas market is evolving in response to the changing needs of market participants

The introduction of LNG has changed the transportation requirements of some gas producers and retailers in the east coast gas market. This served as a catalyst for a series of investments to build, convert to bi-directional flow or expand key transmission pipelines. These developments have increased the connectivity of the transmission pipeline network in the east coast gas market, allowing gas to be transported to the highest value users.

Some of the recently completed developments include the expansion of the Eastern Gas Pipeline (EGP), the conversion of the MSP into a bi-directional pipeline and connection to the EGP, the conversion of MAPS into a bi-directional pipeline and connection to the SEA Gas Pipeline and the conversion of the South West Queensland Pipeline (SWQP) and Queensland to South Australia/New South Wales Link (QSN) into bi-directional pipelines. As a result of these developments, gas from all the basins in the east coast gas market can now reach Queensland and gas produced in Queensland can now be supplied into every demand centre in the east coast gas market.

In November 2015, the Northern Territory Government awarded Jemena the right to construct and operate a new pipeline from Tennant Creek to Mt Isa (the NGP), which is expected to be constructed by 2018.³⁹ This will now link the gas resources in the Northern Territory to the east coast gas market and is likely to encourage increased exploration and appraisal investment, providing the economics warrant it and policy does not discourage it. If such investment is carried out and results in sufficient 2P reserves being identified, this could lead to another pipeline being constructed connecting Mt Isa to Wallumbilla.⁴⁰

The introduction of LNG has also increased the level of reliance of some gas market participants on short-term trading markets. As mentioned earlier, a number of domestic users are now relying on the STTMs and DWGM to meet some of their gas needs. The Wallumbilla GSH was also established in Queensland to support gas trading among LNG participants, other gas producers and domestic users. The LNG projects provided evidence to the Inquiry that they have a significant interest in being able to engage in short-term trades at the Wallumbilla GSH to manage their gas needs. While trading at the Wallumbilla GSH, the STTMs and DWGM is still relatively limited, increased participation by the LNG producers and domestic users over time has the potential to facilitate an increase in diversity of participation and liquidity in trading via those mechanisms.

³⁹ Jemena's media release, 'Jemena to build North East Gas Interconnector'.

⁴⁰ *ibid.*

2 LNG fundamentals influence gas prices in the east coast gas market, with different dynamics emerging in Queensland and the southern states

The commissioning of the LNG export facilities has significantly altered the pricing dynamics in the east coast gas market. The LNG facilities have enabled CSG producers in Queensland to access international gas markets and sell their gas at LNG export prices, which are higher than historic gas prices paid by domestic users under bilateral GSAs. By leaving spare capacity in their trains, the LNG projects have created an additional demand option for producers in the east coast gas market, particularly those located in Queensland and central Australia.

In this environment, international LNG supply and demand exerts a considerable influence on domestic gas prices in Queensland. Due to their proximity to Wallumbilla, Queensland domestic users now have to directly compete with international demand for any uncontracted gas that could be made available to the Queensland domestic market.

The nature of the impact of LNG on the southern states is somewhat different. While there is pipeline connectivity that enables Victorian off-shore producers to deliver gas to the LNG projects for export⁴¹, the cost of transportation is quite significant. This assists domestic gas users in the southern states to compete with the LNG projects for off-shore Victorian gas, particularly at lower oil prices.

However, there has been a significant change in the pricing dynamics in the southern states as a result of the decisions made by the Cooper Basin producers, particularly Santos, to commit significant volumes of gas produced in the Cooper Basin to the LNG projects. The Cooper Basin producers historically played a critical role in competing with the GBJV for market share in the southern states. The reduction in the diversity of gas suppliers in the southern states has substantially strengthened the competitive position of the GBJV and has severely undermined the bargaining position of domestic users in negotiation with the GBJV.

2.1 Prices in Queensland are shaped by LNG fundamentals

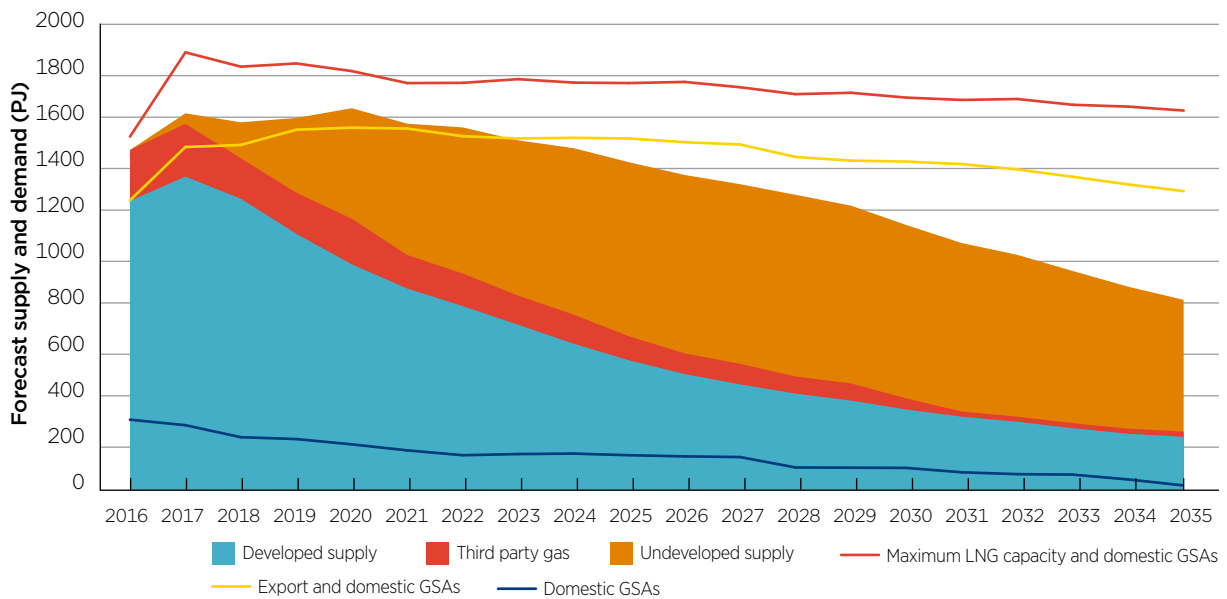
2.1.1 The LNG projects are forecast to have sufficient gas to meet their contractual commitments in the medium term, but may continue to purchase additional third party gas

The three LNG joint ventures have entered into large long-term LNG export agreements to underpin their substantial investment in the development of LNG. These projects also have legacy domestic GSAs, which they are committed to fulfil. The LNG projects require significant volumes of gas in order to meet these contractual commitments. The extent to which the three LNG projects rely on their own reserves to meet their contractual commitments varies. In particular, GLNG has been a material purchaser of third party gas, having acquired substantial volumes of gas from a range of third parties across the east coast gas market over the past five years (as shown in table 1.2 earlier).

The LNG projects currently forecast that they will produce sufficient gas, in addition to the gas already purchased from third parties, to meet their existing export and domestic contractual commitments in the medium term, even in the absence of Arrow gas (chart 2.1). Development of Arrow reserves could considerably improve the supply-demand balance (discussed further in chapter 3).

⁴¹ Producers in off-shore Victoria include those in the Gippsland, Bass and Otway basins.

Chart 2.1: Forecast supply and demand balance of the LNG projects in Queensland, excluding Arrow, 2016–35



Source: ACCC analysis based on data obtained during the Inquiry.

Note: In this chart, 'developed supply' represents production from wells which have been completed or where budget has been approved for their construction; 'third party gas' represents gas purchased from third parties; 'undeveloped supply' represents future expected production from wells which have not yet been approved for construction; 'maximum LNG capacity and domestic GSAs' is a sum of LNG nameplate capacity and domestic contractual commitments of the LNG projects; 'export and domestic GSAs' represents the total export and domestic contractual commitments of the LNG projects and 'domestic GSAs' shows the domestic contractual commitments of the LNG projects. This chart does not include Arrow production forecast as its commercial plans have not yet been announced.

Notwithstanding this, the LNG projects may continue to purchase additional gas to maximise their LNG production, substitute for higher cost reserves or cover any unexpected shortfalls in meeting contractual commitments.

The LNG projects have economic incentives to purchase additional gas to maximise LNG production

The gap between the top demand line and the second demand line in chart 2.1 represents production capacity in the LNG plants above their foundation export GSAs that could be used to sell additional LNG, typically on Asian spot markets. Given the low marginal costs of liquefaction (see section 2.1.2) and the significant capital investments made in these facilities, the LNG projects have strong incentives to maximise LNG production.

The current supply and demand forecasts in chart 2.1 indicate that LNG projects are unlikely to have sufficient gas to allow them to maximise LNG production in the absence of additional and currently unplanned developments (this is represented by the unfilled gap between the undeveloped supply and the top demand line). Therefore, the LNG projects are likely to seek to purchase additional third party gas if it would be economic for them to sell that gas internationally.

Changing resource expectations and challenging economic environment may also necessitate purchases of third party gas

As shown in chart 2.1, the LNG projects rely on production of gas from their undeveloped reserves to meet their contractual commitments. Unlike typical LNG ventures using gas extracted from conventional reservoirs, the CSG based projects require ongoing investment in the drilling of new wells every year to maintain production. New developments often need additional infrastructure to be built, including pipelines and processing facilities. For example, in November 2015, QGC announced that it had made a decision to invest \$1.7 billion dollars into the 'Charlie' project, which allowed for production from its existing tenements as part of the QCLNG project.⁴²

⁴² QGC media release, 'QGC development a vote of confidence in industry', 15 November 2015..

Whether the LNG projects continue to make investments sufficient to sustain production will depend on the economics of new developments. Currently, some of these developments have been put at risk by the challenging economic environment precipitated by the severe downturn in the price of oil. Some LNG projects have also experienced difficulties in extracting reserves, particularly in the Bowen Basin, and higher than expected costs of production (box 2.1).

In these circumstances, the LNG projects could seek to lower their cost of supply by purchasing third party gas to substitute for some of their high cost undeveloped reserves. Deferring production would allow the LNG projects more time to work on improving gas extraction methods and reducing the cost base before undertaking new developments.

Therefore, whether LNG projects continue to participate in domestic markets to buy third party gas depends on the global environment and the economics of CSG development.

Box 2.1 Changing expectations about the recoverability and the cost of extracting CSG reserves

When the three LNG projects were sanctioned, there were high expectations about their production forecasts based on significant volumes of identified 2P reserves. While in some areas, particularly in the Surat Basin, the initial production results have met and even exceeded those expectations, the LNG projects have encountered challenges, which put at risk their ability to sustain the required level of production over the period of their export agreements:

- 2P reserves do not fully reflect the long ‘tail’ associated with CSG production
- low permeability, especially in the Bowen Basin, creates uncertainty about the ability to economically recover those 2P reserves at this time
- higher than expected costs of developing CSG reserves may require higher long-term gas prices to support development of those reserves.

CSG ‘tail’

Conventional gas wells in good quality reservoirs typically sustain high rates of production over many years. By contrast, the production profile of CSG wells is characterised by an initial period of high production followed by a steep decline in production rate and a long production ‘tail’ that may last for a decade or more. If the peak production per well is less than anticipated or the production rate per well declines more rapidly to a lower production ‘tail’ with time, more wells will be required to sustain the required level of production.

Bowen Basin

Some initial drilling results in the Bowen Basin have been poorer than expected as a result of low permeability. This has increased uncertainty about the ability of the LNG projects to economically recover those 2P reserves in the immediate future. Some of these projects have deferred development of those reserves and construction of the associated infrastructure until they develop technology to understand how best to unlock those reserves.

CSG production costs

While the construction of the LNG trains has been smoother than might have been expected given their simultaneous start-up, some LNG projects found the cost of labour, service and capital in the course of construction and the initial LNG production phase to be higher than expected. Well development costs are now falling as pressure on input costs eases and the LNG projects become more experienced at drilling and maintaining wells.

Current 2P CSG reserves are based on best estimates of future production costs. As discussed in section 1.3.1, there are significant uncertainties associated with estimating future CSG production costs. If CSG production costs turn out to be higher than expected, this would require higher prices to support development of those reserves, which could result in production delays. Therefore, it is uncertain whether the timing and volumes of current production forecasts of 2P CSG reserves will be met.

2.1.2 Domestic prices in Queensland are shaped by LNG netback prices

Gas producers in the east coast gas market will have an export option for their gas while any of the LNG projects require additional gas to meet their contractual export commitments or fill spare production capacity in their trains. This means that domestic gas users in Queensland will have to directly compete with the LNG projects for any gas that is available for supply into the Queensland market. The amount that the LNG projects would be prepared to pay for this gas represents the opportunity cost for the east coast producers of supplying gas to domestic gas users. Therefore, in negotiation with domestic gas users, the producers are likely to be seeking a price that is commensurate with an amount the LNG projects are willing to pay.

The presence of an export option will be a key feature of the east coast gas market into the future. This means that the domestic gas prices in Queensland will typically be influenced by LNG netback prices (the LNG export prices netted back to the relevant location), which represent the maximum amounts that the LNG projects would be willing to pay to purchase third party gas. While this is likely to be the predominant situation, circumstances may occasionally arise that will result in domestic prices in Queensland being temporarily delinked from the LNG netback prices (Box 2.2). The remainder of this chapter focuses on the situation where domestic prices in Queensland are actively shaped by the LNG netback prices.

Box 2.2: Circumstances in which domestic prices in Queensland may be temporarily shaped by the marginal cost of gas supply, rather than LNG netback prices

While producers in the east coast gas market will generally have the option of selling gas to the LNG projects, the price the LNG projects may be prepared to pay for this gas could vary. In circumstances where the LNG projects need additional gas to produce at maximum LNG plant capacity or to meet shortfalls in export commitments, the LNG projects are likely to be willing to pay a price for third party gas up to the relevant LNG netback price. There may also be circumstances in which the LNG projects would only be prepared to buy third party gas to displace higher cost production, in which case they would only be willing to pay a price for third party gas up to the marginal cost of the production being displaced.⁴³

Such a scenario could arise, for example, if the LNG projects have already sourced sufficient gas reserves that can be developed economically to fill the trains. In this environment, the domestic prices in Queensland may temporarily delink from the LNG netback prices, as the LNG facilities have no spare capacity to spur their demand for gas. In this case, domestic gas can now only substitute for gas already being supplied to the LNG facilities and so the price is likely to be shaped by the marginal cost of gas production until additional LNG capacity is commissioned. If LNG price expectations are high enough, this will send a signal to the LNG producers to expand existing LNG plant capacity or build an additional train. If either of these situations occur this will increase demand for gas to be supplied to the LNG facilities and likely lead to a return to pricing shaped by LNG netback. However, investments in LNG production are lumpy, high cost and generally require long lead-in times. There is also considerable uncertainty about future oil and LNG prices, which could delay the supply response. So any return to LNG netback pricing may not be automatic.

Domestic gas producers may also view any delinking from LNG netback pricing as temporary, and this may influence their negotiations with domestic users, particularly for longer-term GSAs. To the extent that gas producers view the delinking from LNG netback pricing as temporary, they may consider deferring production as an alternative to selling to domestic users. The attractiveness of this may depend on whether producers have already committed large irreversible investments to the development of gas (such as infrastructure development) and the extent to which they can reduce or defer production from committed developments. It would also depend on their expectations about the future LNG and domestic supply outlook. If producers see deferring production as their best option, producers may still prefer to use the LNG netback prices to inform their negotiations with domestic users.

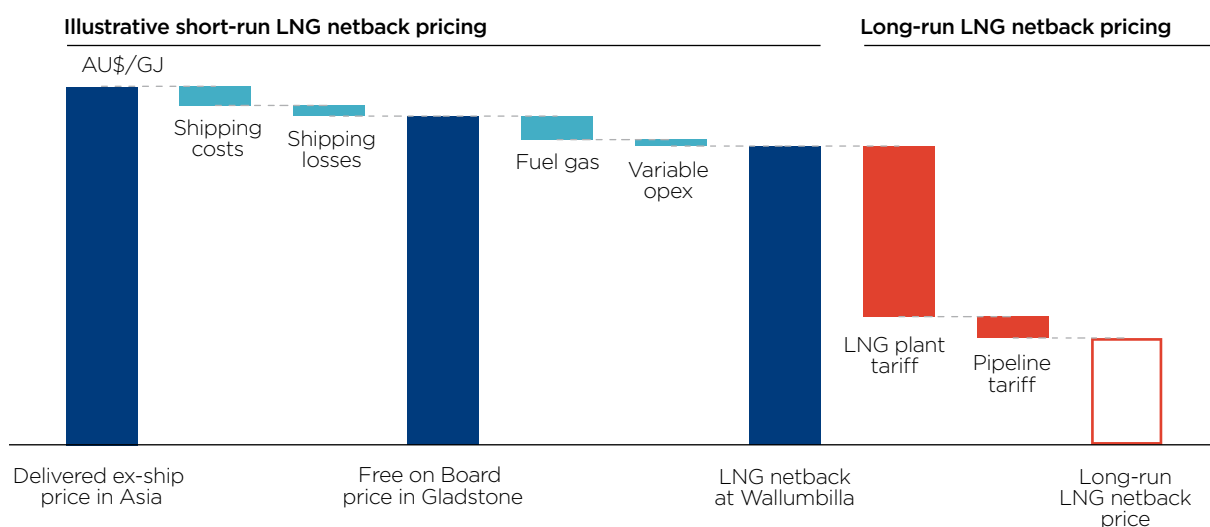
Another possible scenario could arise if, as the result of international oversupply of LNG, the LNG spot prices become so depressed that it would be uneconomic for the LNG projects to sell gas in the LNG spot markets on top of their existing contractual commitments. This may then have the effect of reducing or eliminating the option for domestic producers of gas to sell further gas at LNG spot netback prices. As with the previous example, domestic pricing outcomes may depend on long-term expectations of producers and their perceived alternatives to selling to domestic users.

Calculating the LNG netback price

The LNG netback price at a particular location is calculated by taking the relevant LNG export price and subtracting the cost of shipping, liquefaction and transmission.⁴⁴ Which specific LNG export price is relevant depends on the purpose for calculating the LNG netback price. For working out the economics of LNG spot sales, the starting point is the LNG spot price, which fluctuates with international supply and demand dynamics. For working out the economics of the LNG projects meeting their long-term contractual export commitments, the starting point is the LNG export GSA price, which fluctuates with changes in the price of the commodity to which the pricing formula in the export GSA is linked.⁴⁵

Chart 2.2 illustrates how a delivered LNG price translates into an upstream gas sales price that can be compared to prices in the domestic market.

Chart 2.2: Calculating the LNG netback price at Wallumbilla



43 The LNG netback prices are still likely to set a ceiling for an amount the LNG projects are willing to pay, which would become relevant if the LNG netback prices were to fall below the marginal cost of production.

44 LNG is generally traded in US dollars and millions of British thermal units, so LNG export prices typically need to be converted into AU\$/GJ for comparison with domestic gas prices.

45 The pricing mechanism in the export GSAs of the three Queensland LNG projects is linked to the Japanese Customs Clearance crude oil index, although the precise relationship varies between GSAs.

The 'Delivered ex-ship' (DES) price represents the delivered price of LNG at the destination port. The DES price is netted back to Gladstone by subtracting the short-run shipping costs and shipping losses. The shipping costs reflect the cost of shipping LNG from Gladstone to the destination port, including ship charter costs, fuel, port fees (load and discharge) and insurance. The shipping losses reflect the cost of the volume of gas lost during transit as a result of LNG boil-off.

The 'Free on-Board' (FOB) price represents the price of LNG at the point it is loaded onto a ship at Gladstone. The FOB price is netted back to the LNG netback price at Wallumbilla by subtracting the short-run cost of liquefaction, comprising of the cost of fuel gas and operating expenditure. The cost of fuel gas reflects the cost of the volume of gas consumed during the liquefaction process, which primarily consists of the gas used to fuel the LNG plant. The operating expenditure reflects the variable cost of the liquefaction process, including the use of refrigerants, rotating equipment maintenance costs, service support agreement costs and operating spares. The LNG netback at Wallumbilla is the appropriate LNG netback price to use for comparison to domestic gas prices at Wallumbilla.

The calculation of the LNG netback price at Wallumbilla does not include any allowance for the fixed costs of LNG production or the recovery of the capital invested in the LNG facilities (including gas transmission pipelines from wellheads to the LNG plant). This is because those investments represent sunk costs, which are normally not taken into account in making short-term commercial decisions. This means, for example, that if the LNG projects have spare LNG production capacity, they should be willing to purchase third party gas for re-sale on LNG spot markets as long as the sum of the purchase price and the marginal liquefaction costs is below the FOB LNG sales price.

The long-run LNG netback price in chart 2.2 is presented as a hollow bar because it is a conceptual figure, representing the price level at which the LNG projects would make an acceptable commercial return on their initial investments in the LNG facilities. The LNG joint venture parties sanctioned these projects on the basis of an expectation that they would be able to earn the margins represented by the bars labelled 'LNG plant tariff' and 'Pipeline tariff' consistently throughout the life of the project, generating the required rate of return on the invested capital. Whether these margins will be realised will depend on many factors, particularly the long-term LNG prices and their ability to optimise the cost of production of their own reserves.

To calculate the applicable price at another location in the east coast gas market, the LNG netback price at Wallumbilla needs to be adjusted to account for the cost of gas transmission to, or from, the relevant location. Domestic users outside Queensland need to add the cost of transporting gas from Wallumbilla to their off-take to calculate the gas price based on LNG netback that they could compare with a delivered gas offer from another supplier. By contrast, gas producers outside Queensland that wish to compare the maximum price they may receive from the LNG projects with gas offers from local domestic users, would need to subtract the cost of transporting gas from the user's location to Wallumbilla (see box 2.3 for a worked example).

Box 2.3: Example—the gas price range in Sydney based on the LNG netback price

This example illustrates how to calculate the LNG netback price at Wallumbilla from a given LNG spot price and then translate this into the gas price range at Sydney for a hypothetical gas buyer and gas seller.

Price/Description	Buyer/Seller
Spot LNG (DES) price quoted*	US\$6.13/MMBtu
DES price converted to AU\$/GJ**	AU\$8.07/GJ
FOB price (subtract shipping costs and losses)†	AU\$7.36/GJ
The LNG netback price at Wallumbilla (subtract liquefaction costs)‡	AU\$6.69/GJ
The gas price at Sydney based on the LNG netback:	
- Seller alternative (subtract transportation costs)~	AU\$4.13/GJ
- Buyer alternative (add transportation costs)~~	AU\$8.76/GJ

These two prices represent the price ceiling and floor in negotiations between buyers and sellers (as discussed in detail in section 2.2.3 below).

* Argus LNG Daily, Friday, 5 February 2016 (Argus).

** Conversion rates: AU\$1 = US \$0.72 and 1 MMBtu = 1.0551 GJ.

† Shipping cost from Gladstone to Tokyo = US\$0.32/MMBtu or AU\$0.47/GJ (Argus); shipping losses are estimated at AU\$0.24, based on 3 per cent loss of volume loaded at Gladstone priced at DES price.

‡ Marginal liquefaction costs are estimated at a total of AU\$0.67, based on a 10 per cent mark-up on gas sales price at Wallumbilla. The 10 per cent consists of fuel gas for LNG plant, estimated to be about 8 per cent of gas input to the LNG plant⁴⁶, and operating expenditure, assumed to equate to another 2 per cent.

- Seller transportation costs are estimated at AU\$2.56/GJ, consisting of AU\$0.68/GJ for transmission from Sydney to Moomba (figure 1), AU\$1.26/GJ for transmission from Moomba to Wallumbilla (taken as a mid-point of the range in figure 1), AU\$0.58/GJ for estimated processing toll at Moomba⁴⁷ and AU\$0.04/GJ for cost of gas used in transmission based on 0.9 per cent use estimate⁴⁸ priced at average daily price for the Sydney short-term trading market hub for 2015–16 up to February 2016 (AER website).

-- Buyer transportation costs are estimated at AU\$2.07/GJ, consisting of AU\$1.06/GJ for transmission from Wallumbilla to Moomba (taken as a mid-point of the range in figure 1), AU\$0.98/GJ for transmission from Moomba to Sydney (figure 1) and AU\$0.04/GJ for cost of gas used in transmission based on 0.9 per cent use estimate priced at average daily price for the Sydney short-term trading market hub for 2015–16 up to February 2016 (AER website).

2.2 Prices in the southern states depend on the level and diversity of supply

2.2.1 Gas from off-shore Victoria still flows predominantly to domestic users in the southern states

The attractiveness of the LNG export option for gas producers diminishes the further away their reserves are from Wallumbilla. Gas producers in Queensland are in the best position to sell gas to the LNG projects, given their proximity to Wallumbilla. By contrast, gas producers in the Gippsland, Otway and Bass basins have to transport their gas across a significant distance to deliver it to Wallumbilla. The total cost of gas transportation from the gas plants at Longford or Iona to Wallumbilla amounts to about \$3.50–\$4/GJ (Boxes 2.3 and 2.4).⁴⁹ This makes it easier for domestic users in the southern states to bid the gas produced in off-shore Victoria away from the LNG projects, particularly at lower oil prices.

The ability of southern gas suppliers to flow significant volumes of gas north is also constrained by contractual and physical pipeline limitations. Some suppliers already have established transport positions that link the south to the north, allowing them to move gas to the highest value market. However, this is not the case for most participants in the gas market.

Some parts of the transmission chain are contractually congested. For instance, the existing contractual commitments enabling gas from the Cooper Basin to flow to Wallumbilla limit the amount of spare capacity available for eastward flow on the SWQP. Further, winter peaking demand in the southern states also restricts how much gas can flow north in the winter months

46 Lewis Grey Advisory, *Projections of Gas and Electricity Used in LNG*, prepared for AEMO, 15 April 2015, p. 18.

47 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, March 2015, appendix B, p. 182.

48 Chris Harvey Consulting, *Energy Efficiency Opportunities in Gas Transmission Pipelines and Distribution Networks*, prepared for Department of Resources, Energy and Tourism, June 2013, p. 6.

49 This indicative range is based on tariffs applicable to existing holdings of pipeline capacity.

from Victoria. This is because the pipeline capacity on the EGP and SEA Gas pipelines would be largely utilised to supply Sydney and Adelaide, leaving limited capacity to flow gas further north.

These pipeline constraints can be overcome through secondary capacity trading and/or additional capital investment to enhance physical pipeline capacity. However, this would likely increase the cost of transporting gas to Queensland even further and is only likely to be economic at significantly higher LNG export prices.

The extent to which southern gas suppliers have an opportunity to sell gas to the LNG projects is also currently contingent on their ability to process gas to the specification required by the LNG projects and the price they would have to pay to access or build such processing facilities (see chapter 3 for further discussion).

In the current economic environment, the domestic users in the southern states remain the primary destination for gas produced in off-shore Victoria.

Box 2.4: Transporting gas from off-shore Victoria to Wallumbilla

Gas produced in off-shore Victoria can be transported to Wallumbilla via three separate routes.⁵⁰

Transport Route	From processing facility in Victoria to Moomba	From Moomba to Wallumbilla (all three routes)
Eastern Route (ex-Longford)	Transport via EGP to Sydney and then via MSP to Moomba	
Central Route (ex-Longford)	Transport via the Declared Transmission System (DTS) to Culcairn and then via MSP to Moomba	Transport via QSN/SWQP to Wallumbilla
Western Route (ex-Iona)	Transport via SEA Gas to Adelaide/MAPS and then via MAPS to Moomba	

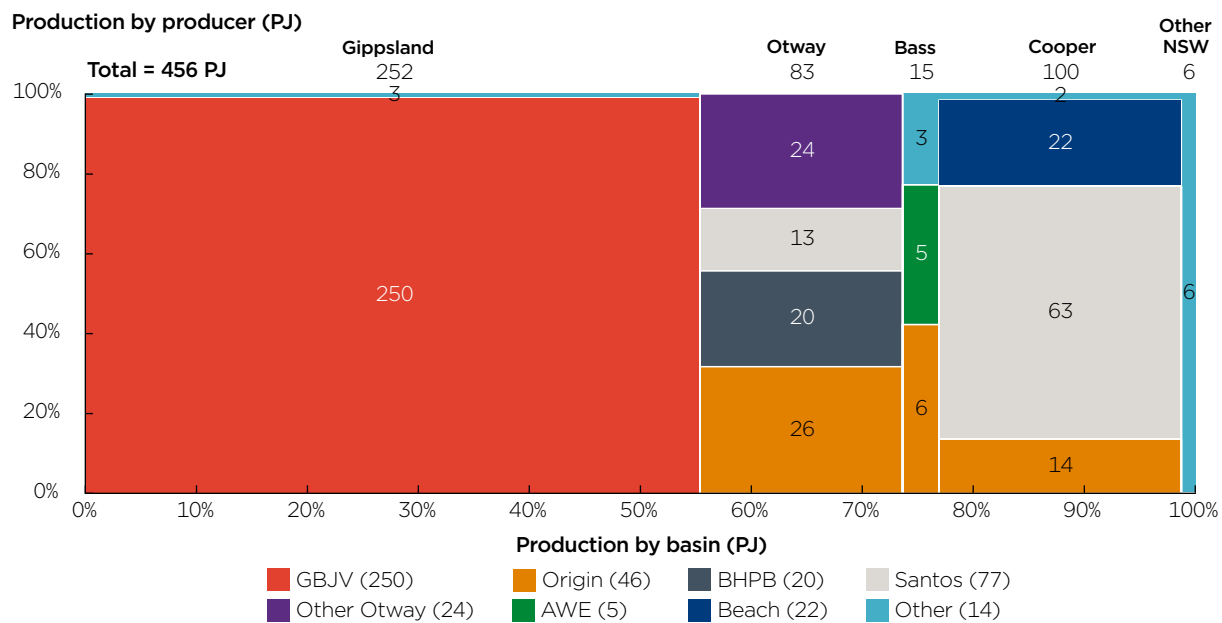
The total distance for each route is approximately 2800–3000 kms. The total cost of transportation for each route is about \$3.50–\$4/GJ, which includes the respective pipeline tariffs (figure 1), processing toll at Moomba and cost of gas used in transmission. Participation in the DTS as part of the central route also incurs a market participation fee.

2.2.2 Domestic users in the southern states are increasingly reliant on gas produced in the Gippsland Basin

Historically, domestic users and retailers in the southern states could purchase gas from suppliers in off-shore Victoria, the Cooper Basin or the Surat Basin. While many gas buyers, particularly in Victoria, relied on supply from the GBJV, the competition from other producers, particularly in the Cooper and Otway basins, was critical to pricing outcomes reached by gas buyers in negotiations with the GBJV (for example, see production breakdown for 2015 in chart 2.3).

50 SEA Gas is the SEA Gas pipeline, MAPS is the Moomba to Adelaide Adelaide Pipeline System, EGP is the Eastern Gas Pipeline, MSP is the Moomba to Sydney Pipeline, Moomba is the Moomba Processing Facility in the Cooper Basin, QSN is Queensland to South Australia/New South Wales link and SWQP is South West Queensland Pipeline.

Chart 2.3 Gas production in the east coast gas market, excluding Queensland, 12 months ending December 2015



Source: Unpublished EnergyQuest data; ACCC analysis.

The competitive dynamics in the southern states are deteriorating considerably. The production in the Surat Basin is predominantly dedicated to supplying the LNG projects. A significant portion of medium-term production from the Cooper Basin has also been committed to the LNG projects (as discussed in section 1.1.2). Gas production in the Otway and Bass basins is in decline, with few new projects identified to maintain production plateau into the future. Since 2013, production in the Otway Basin has fallen by 14 per cent per annum.⁵¹

On 4 February 2016, AGL announced that it would not proceed with the Gloucester Gas Project and would cease production at its Camden Gas Project, raising questions about the future of CSG in New South Wales. Moratoria on onshore gas exploration and development as well as other regulatory impediments in New South Wales and Victoria restrict development of onshore conventional and unconventional reserves in those states.

In this environment, domestic users and retailers in the southern states are becoming highly reliant on off-shore gas production from the Gippsland Basin. The GBJV holds a large portion of the remaining uncontracted low cost conventional gas reserves in the east coast gas market and is now a key source of gas available in the short- to medium-term. The GBJV has given evidence that for 2017 it has sold the highest volume of gas in the history of the Gippsland Basin. Until these competitive dynamics change, the GBJV will have the bulk of market share and will hold significant market power in the southern states.

The Inquiry notes AGL's recent agreement with Cooper Energy to buy up to 53 PJ of gas from the Sole project over eight years and potentially up to 4 PJ per annum from the Manta project.⁵² This could result in new alternative gas supply coming out of the Gippsland Basin, although this is a relatively small volume of gas.

2.2.3 Pricing outcomes in the domestic GSA negotiations are shaped by the competitive dynamics in the southern states

In the absence of a widely accepted external reference price in the east coast gas market, the prices paid by domestic users and retailers under bespoke GSAs with gas producers are determined by the outcome of bilateral negotiations between the parties. As discussed in the previous sections, the LNG projects have changed the alternatives available in these negotiations to both buyers and sellers of gas in the southern states by creating opportunities for gas

51 EnergyQuest, *EnergyQuarterly*, March 2016 and EnergyQuest, *EnergyQuarterly*, March 2014.

52 Cooper Energy's ASX announcement, 'Gas sales agreement with AGL for Sole plus Manta option', 23 March 2016.

producers to sell gas for export and bidding away from domestic buyers significant volumes of gas, particularly from the Cooper Basin.

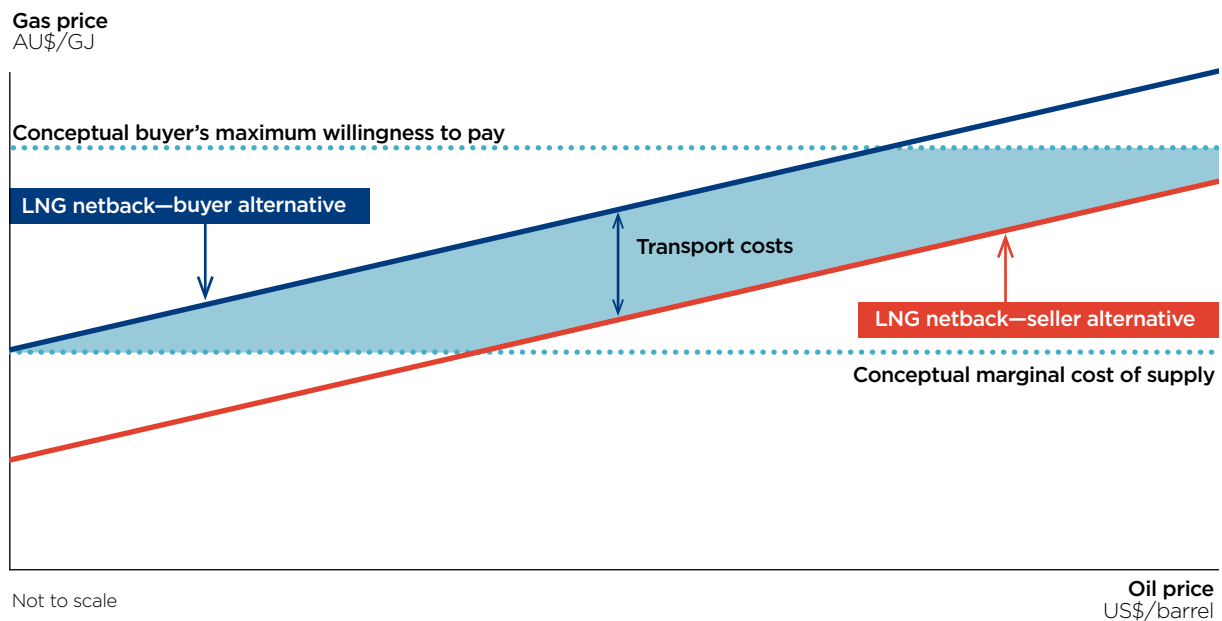
The impact of these changes on pricing outcomes in the southern states can be explained via the bargaining framework illustrated in chart 2.4. This framework is based on the prevailing gas supply-demand balance in the east coast gas market, where prices in Queensland are shaped by LNG export prices (as discussed in section 2.1) and gas producers in the southern states can meet the domestic demand from their own production without requiring gas from Queensland. Material changes to this underlying supply-demand balance are likely to alter the pricing dynamics (box 2.5).

As discussed in section 2.2.1, gas producers in the southern states now have the option of selling gas to the LNG projects, although the attractiveness of this option varies with fluctuations in LNG export prices. While the option to southern producers of selling gas to the LNG projects remains, the price they can achieve from selling to exporters represents the floor price in their negotiations with domestic gas buyers. In chart 2.4, this is represented by the ‘LNG netback—seller alternative’, which is derived by calculating the LNG netback price at Wallumbilla and subtracting the cost of transporting gas from the buyer’s off-take to Wallumbilla (as per box 2.3). The floor price varies with the price of oil, given the current link between oil prices and LNG export prices. Once the LNG/oil price falls sufficiently low to make it uneconomic for gas producers to sell to exporters, the marginal cost of supply becomes the price floor in negotiations.

As discussed in section 2.2.2, gas buyers in the southern states are now heavily reliant on supply from the Gippsland Basin. Given the lack of alternative southern producers that are able to offer significant volumes of uncontracted gas, a buyer’s alternative in the negotiation with the GBJV is likely to be uncontracted gas available in Queensland.⁵³ Given the Queensland market is now being driven by the LNG fundamentals, southern buyers would have to offer the LNG netback price at Wallumbilla to northern producers to bid this gas away from the LNG projects and then transport this gas to their location. In chart 2.4, this is represented by ‘LNG netback—buyer alternative’ (as per box 2.3). This price generally represents the ceiling in buyer’s negotiations with the GBJV. At very high oil prices, the ceiling becomes the buyer’s maximum willingness to pay.

53 This situation is likely to arise if the gas produced from existing and planned developments in the Otway, Bass and Cooper basins is already contractually committed to the LNG projects or other buyers and no new investment is made to produce gas in excess of those commitments.

Chart 2.4: Bargaining framework for gas supply negotiations in the southern states



Note: This chart presents a stylised bargaining framework. The prices achieved by parties in individual negotiations will vary. Prices under bilateral GSAs are also influenced by the specific non-price terms and conditions agreed by the parties. The gap between the buyer and seller alternatives consists of two components—the cost to the buyer of transporting gas from Wallumbilla to their location plus the cost to the seller of transporting gas from the buyer’s location to Wallumbilla, including processing at Moomba and gas losses. The buyer’s maximum willingness to pay and the marginal cost of supply in this chart are purely illustrative.

The gap between the buyer and seller alternatives (capped at the buyer’s maximum willingness to pay and with a floor of the marginal cost of supply) represents the maximum range of possible pricing outcomes in gas supply negotiations between the GBJV and gas buyers in the southern states at a given price of LNG/oil. The size of the gap depends on the cost of transport from Wallumbilla to the buyer’s location and will therefore be larger the further away the gas buyers are located from Wallumbilla.

The prices at each end of this range are unlikely to be realised in practice for a number of reasons, including because the gas market is unlikely to be perfectly competitive or fully monopolistic, the negotiating parties do not have perfect information about the state of the market and may have different expectations about the current and future market conditions. Nevertheless, there is still a considerable range of possible pricing outcomes. Where the domestic gas prices will ultimately end up is likely to depend on availability and diversity of gas supply in the southern states.

In the absence of competitive constraints, the GBJV will hold significant market power and is likely to charge domestic users a price approaching the buyer alternative. It is important to note that while the costs of gas production and processing in the Gippsland Basin are rising, these cost increases are not likely to be the primary drivers of domestic price outcomes in this scenario.

The bargaining framework demonstrates that there are significant gains that could be achieved from bringing on new supply and increasing the diversity of suppliers in the southern states. If significant competition in the southern market re-emerges, the pricing outcomes of negotiations are likely to fall closer to the seller alternative price. Increased competition could potentially result in southern gas users paying up to \$4/GJ less for their gas, which could be as much as one third of the delivered gas price (with marginal cost of supply and the buyer’s maximum willingness to pay influencing the size of the gap at certain oil prices).⁵⁴

⁵⁴ The gain from competition is presented as a range, in part due to factors mentioned earlier affecting actual pricing outcomes and in part because the extent to which domestic users in the southern states are affected by transportation costs varies. For example, because the cost of transporting gas from Wallumbilla to the user’s location, and vice versa, is higher for users located in Victoria than New South Wales, there is a greater range of possible pricing outcomes in Victoria compared to New South Wales and hence a greater potential benefit from increased competition (all else being equal).

The size of any gains that could be achieved from increased competition in the southern states depends on the factors mentioned earlier and also on the cost and location of new gas supply. If the delivered price of gas of a marginal producer in the south is high, either because of high cost or production or being located far from the demand centres in the south, then this sets a high floor in pricing negotiations for all suppliers in the southern states. In this context, moratoria and other regulatory impediments in New South Wales and Victoria may be preventing lower cost gas reserves from being developed that could potentially exert the largest downward pressure on prices in the southern states (refer to chapter 3 for further discussion).

The bargaining framework also highlights the effect of pipeline tariffs across the east coast gas market on pricing outcomes in the southern states. As the gap between buyer and seller alternatives is determined by the transport costs between Wallumbilla and the buyer's location, any monopoly pricing by pipeline operators could be exacerbating the pricing outcomes for domestic users in the southern states in the environment where gas prices are shaped by the buyer alternative (discussed further in chapter 6).

While the bargaining framework is a valuable tool for analysing the parameters in a negotiation for supply of gas, it is important to emphasise that it cannot accurately predict the pricing outcomes of individual negotiations. As mentioned earlier, this is in part because key information affecting individual negotiations, particularly in relation to uncontracted supply and market prices, can be subject to considerable uncertainty in a market dominated by bilateral confidential agreements. Bargaining parties can have different perceptions or expectations about the prevailing and future LNG fundamentals, the LNG netback prices, transport costs, marginal costs and alternatives available to their counterparties. This generally favours producers or retailers over end users as they are typically exposed to a greater number of negotiations and will therefore have a better insight into prevailing market conditions. Therefore, if a reliable indicative price was publicly available, it could help domestic users in bargaining with suppliers (discussed further in chapter 5).

Box 2.5: Bargaining framework under a different supply-demand balance

The parameters and pricing outcomes of the bargaining framework may be different if the supply-demand balance in the east coast gas market changes.

Gas shortage in the southern states

There could be circumstances where the gas producers in the southern states are unable to economically produce enough gas to meet the southern demand due to depletion of conventional reservoirs. Gas from Queensland producers would be required to balance the market. In this scenario, the gas prices in the southern states are likely to be shaped by the buyer alternative (the LNG netback price plus transport cost from Wallumbilla to buyer's location) rather than the competitive dynamics in the south (that is, akin to import-parity pricing).

Changing LNG dynamics

As discussed in box 2.2, there may be some circumstances when domestic prices in Queensland temporarily de-link from the LNG netback pricing. The same is even more likely to occur in the southern states, given their distance from Wallumbilla. If this occurs and the main competitive alternative comes from suppliers located in Queensland, then the marginal cost of CSG production would influence the pricing outcomes in the south. Further, if circumstances change in a way that position the Cooper Basin producers as a genuine competitive alternative to the GBJV, then the marginal cost of conventional or unconventional Cooper Basin production would be relevant.

3 The supply outlook across the east coast gas market remains uncertain

A key question for the east coast gas market is whether there will be sufficient supply over time to meet the rapidly increasing demand for gas. While it is clear that there are sufficient 2P reserves and contingent resources in the east coast gas market to meet likely demand for the foreseeable future, whether these reserves and resources will be developed in time to meet increasing demand is uncertain.

From about 2018, production of 2P reserves from projects that are already producing is not likely to be sufficient to meet the expected demand in the east coast gas market. A number of producers in the east coast gas market have identified specific additional projects that could be developed and have progressed plans to produce gas from the associated reserves. If these producers sanction these projects and meet their current production forecasts, there is likely to be sufficient gas in the east coast gas market to meet domestic demand and existing LNG export commitments until at least 2025. Further developments of additional reserves and resources may be required to produce enough gas to fully utilise the production capacity of the LNG trains.

There are a number of factors that could affect the timing and volume of gas production from the identified undeveloped projects. Low oil prices are impacting on the ability and incentives of gas suppliers to make the investment necessary to bring the undeveloped projects into production. Low LNG spot prices are reducing the prices the LNG projects are willing to pay for third party gas, which may also result in some suppliers delaying sanctioning these projects. Further, major sources of supply that historically have supplied the east coast market are facing increasing production costs and uncertainties.

There are also a number of additional factors limiting new gas developments and the rate at which gas resources are matured into reserves. Moratoria and other regulatory impediments in New South Wales and Victoria are preventing or restricting new developments in those states. Lack of bipartisan support for on-shore drilling in the Northern Territory is creating uncertainty about the development of resources in that territory. Entry into upstream production by junior explorers and producers is difficult due to the high costs and risks associated with gas production. Differences in gas specification requirements between the LNG projects and other users could cause bifurcation in the market and potentially affect development of resources.

In this environment, it is important for policy makers to take these issues into account when considering policies that may impact on gas supply and on prices paid by domestic gas users. The Inquiry encourages governments to consider adopting regulatory regimes to manage the risks to communities posed by individual gas developments on a case by case basis rather than using blanket moratoria. The Inquiry does not support introduction of gas reservation policies, as they are likely to adversely impact on future gas supply.

3.1 A large volume of gas reserves and resources could be developed to meet expected market demand

Chart 1.1 in chapter 1 presented the projected medium-term supply and demand forecast in the east coast gas market. The production forecast was largely based on data obtained directly from producers and was characterised as either relating to developed supply or undeveloped supply.

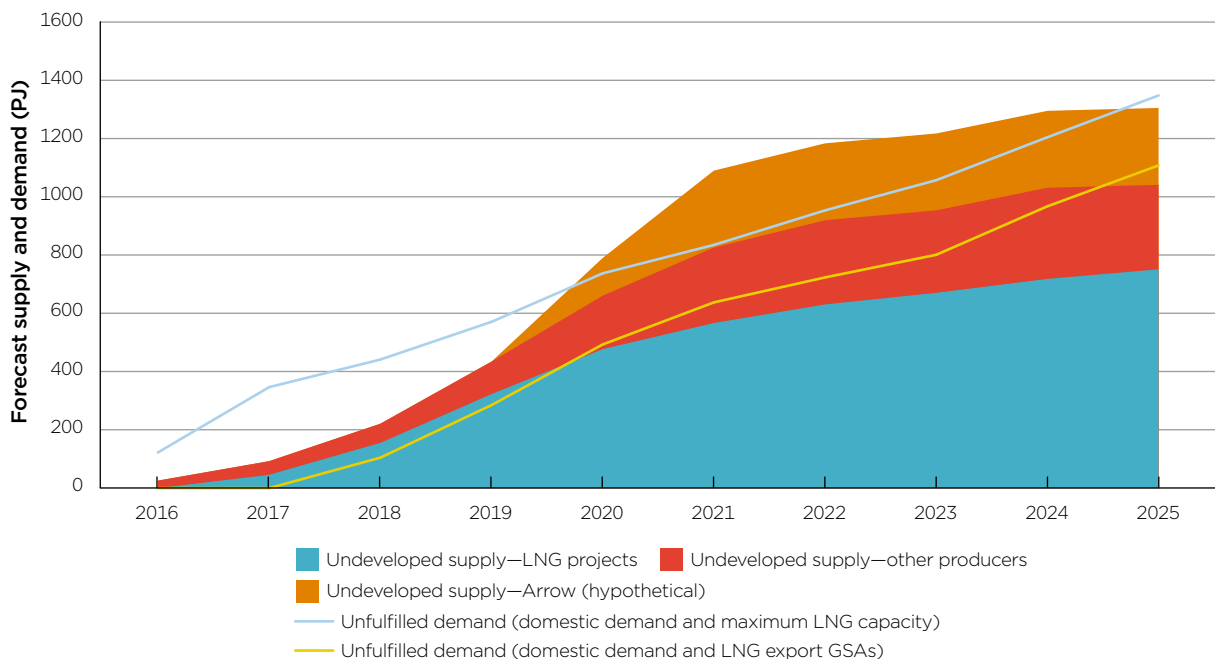
The developed supply included forecast production from currently producing or sanctioned projects. Production from these projects is highly likely to occur, as the capital investment to undertake that production has already been made or committed. The exact timing of gas development from the associated reserves is subject to some fluctuations for commercial or technical reasons, but the forecast volume of production is also made with a reasonable degree of certainty, as these projects are already producing or have undergone extensive testing.

The undeveloped supply included forecast production of 2P reserves in projects that have not yet been sanctioned. Production forecasts in relation to these projects are more uncertain. These projects require additional investments to be approved before production can commence. These investments will need to meet the financial targets of the relevant companies at the time they are made, which will depend on expectations about future market conditions at the time of investment. In addition, most undeveloped projects have less testing and other technical work associated with them, so the volume expectations are less certain.

Despite this, the undeveloped supply forecasts in chart 1.1 relate to identified projects which the relevant producers expected to proceed at the time they provided the data. Many producers have identified additional gas reserves or resources which may potentially be developed at some point in the future, but which they have not included in their own production forecasts due to commercial or technical uncertainties. More uncertain developments of this type are not included in the forecast in this report.

Chart 3.1 assumes that developed supply in chart 1.1 will be produced and presents only the projected undeveloped supply against the remaining unfulfilled demand. That is, the top line in chart 3.1 represents the maximum level of unfulfilled demand that would be expected to be in the market if none of the forecast undeveloped reserves were developed (that is, the gap between 'Domestic demand and maximum LNG capacity' and 'developed supply' in chart 1.1). The lower line in chart 3.1 represents the level of unfulfilled demand that would be expected if the LNG projects sought only to meet their existing contractual commitments and not attempt to fully use their plants. The undeveloped supply for the LNG projects and other producers in chart 3.1 is the same as in chart 1.1. A hypothetical Arrow forecast has also been added for completeness.

Chart 3.1: Unfulfilled demand and forecast of production from identified undeveloped projects, 2016–25



Source: Data obtained by the ACCC during the Inquiry, EnergyQuest, *EnergyQuarterly*, March 2016 and AEMO's *2015 National Gas Forecasting Report*.

Chart 3.1 shows that gas from undeveloped projects will need to be brought into production in order to meet expected domestic demand and LNG export contractual commitments beyond 2017. However, as noted above, at the time of providing information to the Inquiry, the relevant producers planned to develop the reserves in the 'undeveloped supply—LNG projects' and 'undeveloped supply—other producers' categories in line with this forecast. If these expectations are met, then there is likely to be sufficient gas in the market to meet domestic and LNG export contract demand until at least 2025.

Chart 3.1 also shows that there is very likely to be spare capacity in the LNG trains until at least 2020 (the gap between the top line and undeveloped supply). There is also likely to be some spare capacity in the LNG trains beyond that unless Arrow's reserves are developed (and provided such development doesn't significantly displace development of other reserves).

The undeveloped projects in chart 3.1 are expected to produce gas from three categories of reserves:

- **LNG reserves.** These are CSG reserves held by the LNG projects. Development of these reserves, over time, was sanctioned in the initial decision to proceed with the relevant LNG project. However, due to the nature of CSG reserves, only a proportion of the infrastructure (including wells, pipelines and processing facilities) needed to extract this gas was built at the start of the project and continual additional investment is required over time to meet the initially-proposed development path. The LNG projects have a strong incentive to develop their reserves, particularly in order to meet their export contract commitments, but only if the incremental investment is commercially attractive at the time it actually needs to be made.
- **Arrow gas reserves (hypothetical).** The Inquiry is not aware of any firm commercial plan to develop the Arrow gas reserves in Queensland. As discussed in more detail below, the hypothetical estimate provided in chart 3.1 is based on public information regarding the potential size and earliest possible timing of development of those reserves. This estimate is provided to demonstrate the potential size of the Arrow development relative to other undeveloped reserves in the market and should not be regarded as a forecast of likely production.
- **Other reserves.** The projects in the 'other producers' category relate to undeveloped reserves on the east coast that do not fall into the above two categories. These reserves include both conventional and unconventional reserves across each of the major basins on the east coast.

Beyond the projects included in this forecast, there are a number of other potential gas resource developments and new exploration projects and opportunities across the east coast gas market. These include speculative unconventional projects in Queensland, South Australia and the Northern Territory and potential new gas fields in deeper water further offshore from Victoria. In addition, the recent planned connection of the Northern Territory to the east coast gas market represents a major new potential source of supply in the longer term (discussed further below). The Inquiry has not attempted to forecast the volume of gas that could be produced from such projects although, if successfully explored and economic to develop, they will be important for new supply into the future.

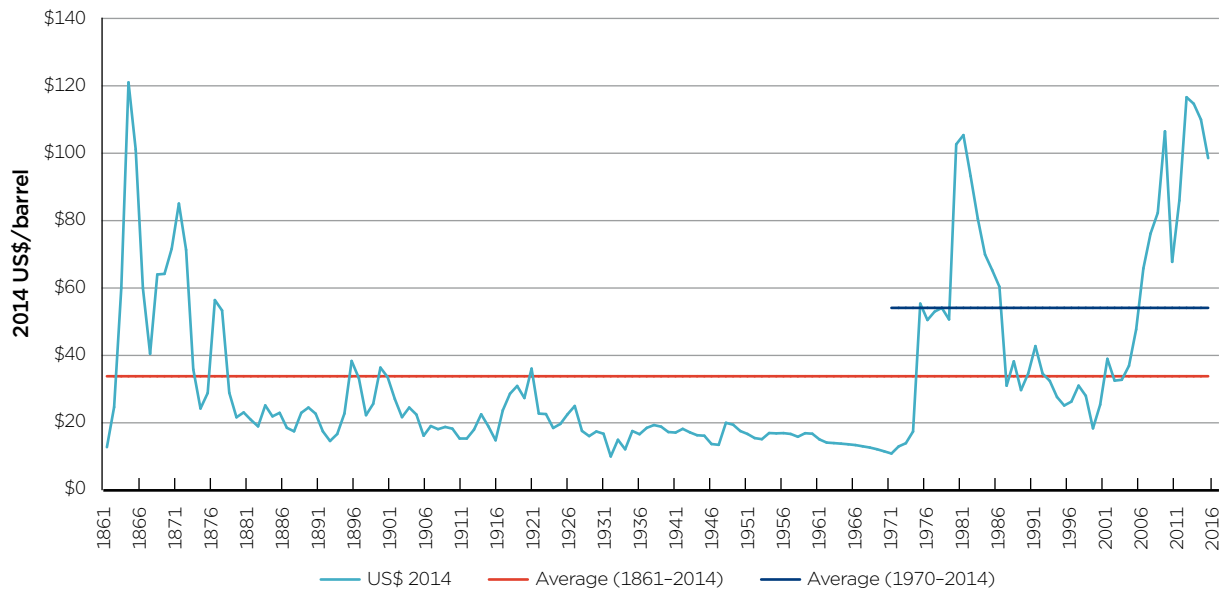
3.2 There are significant commercial uncertainties associated with development of reserves and resources

3.2.1 Low oil prices reduce the investment funds available for gas exploration and development

A major factor affecting the supply outlook for the east coast gas market is the current oil price. As discussed in chapter 1, the LNG projects have resulted in the introduction of oil-linked pricing in the east coast gas market. This means that the commercial incentives to develop gas on the east coast are linked to the global price of oil. The oil industry has historically been characterised by cyclical prices, where new investment increases with price upswings and exploration and development levels contract as prices fall. Because oil projects can take up to 10 years from initial exploration to result in production, the market response to short-term price signals can lead to under investment in future production when oil prices are low, and over investment when oil prices are high.

The real average price of oil in the post OPEC period is about US\$55/barrel (1970-2014; in 2014 dollars, chart 3.2). The nominal price of oil averaged above US\$100/barrel for most of 2011-2014. Since then oil prices have fallen significantly, to as low as US\$28/barrel in January 2016. As at 1 April 2016, oil prices were about \$40/barrel, which represents a return to a price level closer to the long-run real average price.

Chart 3.2 Real long term oil prices, 2014 US\$/barrel



Source: BP Statistical Review of World Energy, 2015.

Low oil prices reduce the investment funds available for oil and gas exploration and project development in the east coast gas market in a number of ways. Some producers, including the LNG projects and each of the large domestic suppliers (Santos, Origin and the GBJV), are businesses with significant oil exposure arising from being a party to or having a significant financial interest in oil-linked GSAs, or by being involved directly in the production and sale of oil. The low oil price affects the cash flow and balance sheet of these companies and the lenders and shareholders of these companies are less willing to provide additional funds to finance exploration when oil prices are low. An example of the impact of oil prices on businesses with direct exposure to the oil price is the \$1.6 billion impairment of Cooper Basin assets announced by Santos in February 2015, due to an update to their oil price estimate.⁵⁵ As discussed further in chapter 5, the effect of changes in oil price forecasts on reserves is currently reported to the public on an adhoc basis by the relevant companies. Other companies without direct oil exposure may face difficulties in obtaining finance to fund projects because investors will see low oil prices as a signal of low future gas prices in the east coast gas market.

Both APLNG and GLNG have stated that they are cash flow positive at average oil prices of around US\$40–45 per barrel.⁵⁶ At oil prices below this level, these projects will face difficult decisions around the investments required to maintain steady state production, which will have a total value of billions of dollars. As a result these projects may consider options such as purchasing additional third party gas, if it is available in a contractually permissible location and on commercially attractive terms, or renegotiating the terms of their export GSAs with their customers.

Therefore, if the current low oil prices continue for a number of years, major domestic producers may find it more difficult to invest in their currently proposed development opportunities and significant volumes of currently undeveloped forecast future production in the east coast gas market may face delays.

⁵⁵ Santos ASX announcement, 'Impairment of Assets: non-cash charge of \$1.6 billion after tax', 12 February 2015.

⁵⁶ Origin Energy investor presentation, 'Update on Amended Loan Facilities and APLNG', 11 December 2014 and Santos GLNG factsheet, October 2015.

3.2.2 The volume, timing and market effect of Arrow's reserve development is uncertain

The Arrow Joint Venture holds the most significant uncommitted gas reserves in the east coast gas market (table 3.1). These reserves consist of CSG in the Bowen and Surat basins. Arrow initially proposed to use the gas in these reserves to underpin a fourth LNG project in Queensland, but Shell formally announced the cancellation of this project in early 2015.

Table 3.1: Arrow operated reserves at February 2016

	Surat (PJ)	Bowen (PJ)	Total (PJ)
Arrow 2P reserve estimates	7 561	2 677	10 238

Source: EnergyQuest, *EnergyQuarterly*, March 2016.

Note: The estimates presented in this table are based on reserves in Arrow operated areas. This includes 8915 PJ of Arrow-owned reserves and 1323 PJ of reserves owned by other parties.

The majority of Arrow's reserves are in the Surat basin. Arrow has an approved environmental impact statement in relation to its Surat Gas Project under which it proposed to develop reserves up to production of one LNG train per year (~265 PJ) using approximately 6500 wells. Much of Arrow's Surat acreage is located in areas where there is some existing CSG infrastructure, particularly belonging to QGC, a subsidiary of the BG group. Shell has stated that the merger between Shell and BG, which was completed on 15 February 2016, is the best way to bring Arrow gas to market as it will enable both Arrow and QGC to access existing pipelines and processing facilities in the Surat Basin.⁵⁷

The Arrow reserves in the Bowen Basin are currently not connected to Gladstone or the east coast gas market. Bringing this gas to market would require the construction of a pipeline of approximately 500 km. Arrow has an approved environmental impact statement in relation to the Bowen Gas Project, which describes a project scale involving up to 6625 wells over the 40-year life of the project. In September 2014, Arrow announced that the project was entering into a front-end engineering and design phase. Arrow expected that this would take about 12 months, however, it has not yet announced the result of this phase.

If either of the proposed major Arrow gas projects were developed, it would be a significant source of gas production in the east coast gas market. Arrow states that phase one construction of its Surat Gas Project would take approximately 3.5–4 years.⁵⁸ This time frame, and the stated potential to produce up to one LNG train of gas per year, is the basis for the hypothetical estimate of Arrow's production in chart 3.1.

As shown in chart 3.1, it is possible that development of the Arrow gas reserves could increase supply above market demand. As described in box 2.2, this is one of the scenarios that could cause domestic prices to become delinked from international LNG prices, at least for a period of time.

However, there are a number of factors that reduce the likelihood of this scenario developing. In particular, if a major tranche of Arrow's gas was developed, it is probable that this development would displace the development of some higher cost gas in the market. This is particularly likely to be the case if the effect of both developments going ahead would be to cause the market to be oversupplied relative to the capacity of the LNG facilities, causing gas prices in the east coast gas market to potentially fall below the LNG netback price. Such a situation could undermine the economics of the investments which could generate such oversupply.

The Inquiry expects that development of Arrow's gas would be underpinned by a large foundation GSA from an LNG project, as the project requires a foundation GSA of a greater size and length than any domestic customer would be able to offer. While the Inquiry is not aware of any specific business plan to develop Arrow's gas at this stage, the merger between BG and Shell may offer this gas a clearer path to market than has previously existed.

⁵⁷ Shell Australia Chairman Andrew Smith says LNG needed to develop Arrow gas, *Sydney Morning Herald*, 12 November 2015.

⁵⁸ Arrow Surat Gas Overview, November 2013.

3.2.3 The Northern Gas Pipeline opens up a new potential long-term source of supply, but the extent of future development is currently uncertain due to lack of bipartisan support for onshore drilling

In November 2015, the Northern Territory government announced that it had selected Jemena to construct a pipeline to connect the Northern Territory with the east coast gas market for the first time. The pipeline, named the Northern Gas Pipeline (NGP) by Jemena, will run between Tennant Creek and Mt Isa and is expected to start operating in 2018.⁵⁹

Jemena recently announced that the size of the planned NGP will allow for transportation of approximately 30–35 PJ of gas per annum.⁶⁰ While such volumes would be relatively modest in the context of the overall east coast gas market, they would still add important incremental volumes to domestic supply in Queensland. In addition, the NGP is designed to be scalable if further gas reserves in the Northern Territory are developed.⁶¹ Provided access on reasonable terms to all relevant pipelines is available to prospective suppliers in the Northern Territory, this connection could stimulate new gas exploration and potential new gas development in the Northern Territory.

There is a large potential gas resource in the Northern Territory. The Northern Territory Government's estimate is that there may be in excess of 200 000 PJ of shale gas in the Territory.⁶² A number of companies, including Origin, Santos, Pangea Resources and INPEX are actively exploring or finalising various approvals and agreements in advance of exploring for onshore gas in the Northern Territory. However, it is emphasised that a great deal of work, time and capital is required to prove up these potential resources and recent history across a number of basins both in Australia and internationally shows that actual production may not meet the initial projections.

Although this gas would enter the east coast gas market at Mt Isa in Queensland, it has the potential to assist users across the east coast to source gas on competitive terms over time. The introduction of gas from the Northern Territory to Mt Isa would enable gas, which would otherwise have been needed to supply users in Mt Isa to be supplied to other locations. Over time, if the volumes supplied via the pipeline increase, additional gas could be made available to users across the east coast gas market. However, the further those users are located from the Northern Territory, the more expensive it would be to transport the gas from the Northern Territory to those users.

Overall, the NGP is a positive development for the east coast gas market as it enables the Northern Territory to be potentially a major new source of gas to meet east coast demand in the long term. However, it is currently uncertain to what extent, or over what time period, these shale gas resources will be commercially extracted. While the chance that they will be extracted sooner has increased due to the Northern Territory being connected to a major new market, many resource developers are currently deferring investing in gas development due to the lack of bipartisan support for onshore drilling. This has resulted in Jemena reducing the size of the planned NGP by about a quarter from the size it initially planned when it won the contract from the Northern Territory government.⁶³

3.2.4 There could be significant reduction in production from traditional sources of domestic supply in the southern states

The LNG-driven increase in gas demand in the east coast gas market has created new supply opportunities for traditional domestic gas suppliers. These new supply opportunities have resulted in investment in new supply being made earlier than it otherwise would have been. However, this increase in supply means that the easier to extract resources at major fields will be depleted more quickly than they otherwise would have been. In the absence of further exploration and investment, which is uncertain and costly, there is a potential for decline in supply from these sources.

59 This planned pipeline was previously referred to as the North East Gas Interconnector.

60 'Jemena forced to reduce NT gas pipeline size amid drilling opposition', *The Sydney Morning Herald*, 3 April 2016.

61 Media release, 'NT announces Jemena to build gas pipeline to east coast', 17 November 2015.

62 See <http://www.core.nt.gov.au/Content/File/InvestmentAlert/ShaleGasPotential.pdf>.

63 'Jemena forced to reduce NT gas pipeline size amid drilling opposition', *The Sydney Morning Herald*, 3 April 2016.

The Cooper Basin is an example of a conventional gas production field that has experienced accelerated development as a result of increased LNG demand. In 2010, Santos entered into an agreement with GLNG to supply 750 PJ of gas over a period of 15 years (the Horizon GSA).⁶⁴ At the time, Santos indicated that this GSA would be used to underwrite the long-term future of the Cooper Basin. Santos' joint venture partners in the Cooper Basin, Origin and Beach elected not to supply their volumes into the Horizon GSA, meaning that Santos has accelerated reserve development to meet its contractual commitments.⁶⁵ Partially as a result of this increased pace of development, many costs of development in the Cooper Basin have been and will continue to increase. Additionally, the conventional gas reserves in the basin will be depleted sooner than they otherwise would have been.

Table 3.2 contains an estimate of the remaining reserves and contingent resources in the Cooper Basin. Santos describes approximately half of its 2P reserves in the Cooper Basin as undeveloped.⁶⁶ These reserves are associated with existing developed reserves, but are not able to be produced without additional investment. Santos considers that there is an expectation that these volumes of gas will be developed, and at such time, they would be reclassified as developed.

Table 3.2 Cooper Basin gas reserves and resources as at February 2016

	2P reserves (PJ)	2C resources (conventional) (PJ)	2C resources (unconventional) (PJ)
Cooper Basin	1203	1359	8429

Source: EnergyQuest, *EnergyQuarterly*, March 2016.

Almost 80 per cent of remaining contingent resources in the Cooper Basin are from unconventional sources. There are significant technological challenges associated with extracting these resources, which primarily consist of shale gas. Major cost savings or very significant increases in the expected sale price will be required for these to be extracted on a commercial basis. According to Santos, the technology to extract these resources may be more than five to 10 years away.⁶⁷

In order to prevent a significant drop off in production from the Cooper Basin, the Cooper Basin Joint Venture will need to make further investment to enable production of reserves that are currently classified as undeveloped. The cost of these investments could be relatively high due to the accelerated schedule of development in the Cooper Basin in recent years. While Santos currently expects that these undeveloped reserves will be developed when required, the joint venture may be somewhat constrained in its ability to make additional investments in a low oil price environment.

Production from another traditional source of domestic supply, the Otway Basin, is expected to significantly decline in the coming years. Production at the large Minerva field, which accounted for 26 per cent of production in the basin in 2015⁶⁸, is expected to cease in approximately 2016. Declines at many other fields in the basin are expected to begin in the early 2020s.⁶⁹ One of the largest prospective developments in the basin is in the Halladale and Speculant fields, which are under development by Origin. This project is currently not expected to produce a volume of gas that would prevent a significant decline in overall production in the Otway Basin.

Future production from the Gippsland Basin also faces significant challenges. The most recent major project in the basin, Kipper Turrum Tuna (KTT), commenced construction in 2013 and was intended to maintain existing gas production levels beyond 2016. In 2013, the total cost of this project was approximately \$4.5 billion, which included the installation of expensive additional processing infrastructure.⁷⁰

64 Santos' media release, 'Santos to supply 750 PJ of portfolio gas to GLNG', 25 October 2010.

65 Santos' presentation, 'Cooper and GLNG Investor Visit', 20–23 April 2015, p. 18.

66 Santos' *Annual Report 2014*, pp. 11–15.

67 'Shale gas success still a decade away for Australia, says Santos', *The Australian*, 26 September 2014.

68 EnergyQuest, *EnergyQuarterly*, March 2016, table 37.

69 AEMO, *2015 Gas Statement of Opportunities*, p. 7.

70 ExxonMobil, Fact Sheet: Kipper Turrum Tuna, October 2013.

The new infrastructure built as part of the KTT project includes the \$1 billion gas conditioning plant 1 (GCP1) facility. This facility was required as gas from the KTT fields contained higher levels of mercury and carbon dioxide than historic production fields in the basin. While the exact composition of gas from future production fields in the basin is uncertain, it is likely that they will also contain levels of carbon dioxide sufficient to require processing by a gas conditioning plant. The processing capacity of GCP1 is 400 million cubic feet per day⁷¹ (approximately 156 PJ per annum), which only covers about two thirds of approximately 250 PJ produced by the GBJV in 2015.⁷² Therefore, as production from legacy fields with low impurities in the Gippsland Basin declines, the GBJV will need to invest in an additional, expensive, gas conditioning plant to prevent a significant fall in production, providing there is further undeveloped gas available.

There is the potential for some smaller undeveloped gas resources to be progressed or further discoveries to be made in the offshore Victorian gas basins. For example, Cooper Energy is partnering with Santos to develop the offshore Sole gas field (originally discovered in 1972) and is looking at gas development options for the Basker Manta Gummy project. On 23 March 2016, Cooper Energy announced a binding heads of agreement with AGL for supply of up to 53 PJ of gas from the Sole project over eight years and potentially up to 4 PJ per annum from the Manta project, subject to final investment decision (expected later in 2016).⁷³

Given the above factors, it is unlikely that there will be any overall increase in production from conventional sources of gas supply. It is more likely that gas supply from these sources will decline in the near future placing pressure on the domestic market, due in part to LNG demand and in part to field decline. While there is potential around unconventional gas sources, many of these remain to be proven.

3.2.5 New entry into upstream production is difficult

Development of gas resources in new areas can potentially increase the availability of gas and diversity of supply in the east coast gas market. However, gas explorers and small new producers in particular face major challenges to achieve the scale necessary to enter the market for the wholesale supply of gas due to the cost and risks associated with gas production.

Gas exploration and production have high capital costs, are high risk and have long project execution timeframes. Petroleum exploration and production permits, whether offshore or onshore, typically require work commitments such as seismic surveys and/or drilling wells. These investments tend to be sunk costs, where the investments have few alternative uses in the event that no gas is discovered. Exploration is also characterised as an activity with a low and uncertain probability of success.

The cost of exploration is substantial. EnergyQuest has estimated an average cost of almost \$6 million per onshore well in South Australia and \$2.5 million per well in Queensland for 2013 where the CSG requires shallower and simpler wells.⁷⁴ Offshore wells can cost over \$200 million depending on water depth, target depth and the complexity of geology and drilling operations. These high costs mean that smaller individual companies are typically confined to onshore exploration or only initial offshore exploration activities, such as data reviews with more costly activities such as seismic shooting or drilling wells requiring farm-in arrangements to bring in other parties to share costs and risks. As a result, frontier offshore exploration is now almost exclusively the domain of larger players with access to substantial capital.

The characteristics of CSG affect the relative importance of sunk costs for CSG development. CSG wells in Queensland are shallower, have lower pressure, and produce gas with fewer impurities than most conventional gas reservoirs. Wells require a period of dewatering to come into production with ongoing water production over the life of the well. Gas production per well is lower and over a shorter life span, which means continuous well drilling over the life of a project is required to maintain production. The initial capital outlay for CSG field development

71 BHPB media release, 'Longford Gas Conditioning Plant Project Approval', 13 December 2012.

72 EnergyQuest, unpublished data, March 2016.

73 Cooper Energy, ASX announcement, 'Gas sales agreement with AGL for Sole plus Manta option', 23 March 2016.

74 EnergyQuest 2014, *Oil and gas industry cost trends*, an independent report prepared by EnergyQuest for APPEA, 1 November 2014, p. 11.

is typically lower than for offshore gas developments. However, maintaining CSG production requires higher operating cost and ongoing capital expenditure to support a continuous program of drilling and new infrastructure development. So despite the somewhat lower upfront sunk costs, the higher ongoing costs mean that CSG field development still requires access to substantial capital.

The combination of large upfront costs, significant time to recover those costs and the riskiness of gas field development contributes to challenges in financing gas production. Because they are capital-intensive, they have traditionally been debt-financed, and lenders have commonly required long-term contracts to ensure debt service. Financiers typically seek confirmation of the existence of user and transport contracts, which creates coordination challenges for new producers.

3.2.6 Gas specification is an emerging issue

Natural gas from different sources will have different compositions. The major component in most cases is methane but gas may also contain various higher end hydrocarbons (ethane, butane, propane, pentane condensates, etc.), a range of inert gases (for example, nitrogen and carbon dioxide) and various potential contaminants (for example, water, sulphur dioxide). Gas which comprises predominantly methane is classified as a 'dry' or 'lean' gas while gas with high end hydrocarbons and condensates may be classified as a 'wet' gas.

CSG in Queensland is classified as a dry gas. It can be used in place of conventional gas from the Cooper Basin or the offshore gas basins as an input to the gas supply chain and can be used in the same manufacturing or heating processes across the east coast gas market.

Natural gas transported via pipelines in the east coast gas market is required to meet the Australian natural gas standard AS4564-2011. Both CSG and conventional gas meet the Australian standard requirements. However, the LNG projects use technology that is well suited to CSG as the feedstock. If it would be necessary for all gas entering Queensland to be processed to the specification of the LNG plants, this may bifurcate the east coast gas market and could affect liquidity in the market in the future.

LNG plants require a dry gas specification

The process of liquefying natural gas first requires the removal of contaminants (such as water, carbon dioxide, nitrogen and sulphur) before gas is fed into the plant for cooling to a temperature of -161 degrees celsius and eventual liquefaction. The transformation from a gaseous to liquid state reduces the volume by around 600 times making it possible to economically transport of gas as LNG.

The LNG plants can generally be optimised to suit the gas composition of the source gas and are able to handle different levels of higher end hydrocarbons. The LNG plants in Queensland are optimised to run on a dry gas specification, which reflects the use of CSG as the major gas source.⁷⁵ Both APLNG and GLNG in their Environmental Impact Statements (EIS) for the projects expected feed gas compositions of around 94-96 per cent methane, 3-4 per cent nitrogen and 0.5-1 per cent carbon dioxide with virtually no higher end hydrocarbons present.⁷⁶

Given this gas composition, the LNG projects appear not to have required additional technology or processing within the LNG plants to cope with higher-end hydrocarbons in their gas supply streams. This included GLNG at the time of their EIS (2009) where only one train was expected initially to be constructed before 2015 with all gas coming from CSG tenements. Since the 2009 EIS, GLNG brought forward the construction of Train 2, which also required purchasing third party gas, including non-CSG gas. GLNG is relying on the Moomba Processing Hub (MPH) to ensure that its third party gas meets the gas specification for its LNG plant. The MPH includes processing to remove the high end hydrocarbon and a range of inert gases and impurities.

75 All the Queensland projects use ConocoPhillips' Optimised Cascade® Process technology which was developed for the world's first lean gas LNG development at Kenai in Alaska in 1969—see <http://www.statedevelopment.qld.gov.au/resources/project/australia-pacific-lng/aplng-ias-27-mar-09.pdf> accessed on 22 March 2016.

76 See <http://www.aplng.com.au/environment/our-environmental-impact-statement> and <http://www.santosgng.com/resource-library/glng-eis/section-03-project-description.aspx> for the relevant EIS for each project.

GLNG considers that its LNG plants could be at risk if gas from other sources is introduced into the Queensland gas transmission network because this gas may not meet the dry gas standard required for its LNG plants and could potentially damage liquefaction equipment. This could include any gas from the Cooper Basin, the southern offshore basins or the Northern Territory that is supplied by producers who do not utilise the MPH.

GLNG has installed monitoring instruments on pipelines to ensure that gas flowing towards the GLNG Pipeline and its LNG plant meets the required specification. If non-LNG specification gas is detected heading towards the GLNG Pipeline, the company would work with pipeline operators to reduce the likelihood of that gas reaching the LNG plant.

GLNG has investigated the potential installation of additional treatment facilities at Wallumbilla to treat gas prior to its injection into the GLNG pipeline. GLNG gave evidence to the Inquiry that this would not be economic, costing between \$600 million to \$1 billion to install suitable gas treatment facilities. These facilities may only be required to remove small amounts of higher end hydrocarbons or inert gases from the pipeline gas stream to ensure the efficient operation of the LNG plant. In addition, such a plant would duplicate the capability already installed at the MPH.

However, in its publicly available 2013 submission to the National Competition Council applying for a 15-year no-coverage determination of its pipeline, GLNG Operations Pty Ltd on behalf of the GLNG project partners, noted the possibility of what they claimed as unsuitable Australian standard gas being in the pipeline system and that GLNG:

“...will construct the Treatment Facility if necessary to ensure that all gas purchased from third parties by GLNG or stored in the Roma Underground Gas Storage Facility meets the specification and contaminant design limits before it is injected into and transported through the Pipeline to the LNG Facility.”⁷⁷

The submission went on to note that if other third party gas suppliers wanted to transport gas via the GLNG pipeline, they too would have to construct suitable gas treatment facilities to ensure that the gas would meet the LNG specification. It is clear that at least in 2013, GLNG envisaged treating gas itself prior to it entering the GLNG pipeline and not requiring all gas in the Queensland gas transmission system to comply with its LNG specification rather than the Australian standard for natural gas.

Implications of a bifurcated market

GLNG's greater reliance on third party gas outside Queensland and the need for its plants to run on gas that meets its LNG specification can potentially create difficulties for other market participants. Specifically, it is possible that other users in Queensland may face additional costs for processing their gas to the LNG specification rather than just the Australian standard. This more costly additional processing requirement may also reduce the incentive for new gas producers to explore for and develop new gas projects in some areas outside of Queensland.

The evidence given to the Inquiry supports this. For example, one market participant stated that gas from the other sources may require additional processing at the MPH prior to being sent into Queensland via the SWQP which would impose additional costs on users in the Queensland market. This is despite the current gas transportation agreements requiring shippers to supply gas at the Australian standard and pipeline operators to transport gas at the Australian standard.

A similar issue may arise once the planned NGP is constructed, connecting gas produced in the Northern Territory to the east coast gas market. If construction of the NGP facilitates additional gas development in the Northern Territory or northern Queensland, any gas moving south of Mount Isa may also require additional processing and additional costs to meet the LNG specification.

⁷⁷ Santos GLNG project, 'Application for 15-year no-coverage determination under section 151 of the National Gas Law', 5 March 2013, p. 5.

Access to gas processing facilities could become more critical in a bifurcated market

While the Inquiry did not receive any clear evidence that access to processing facilities is currently an issue of concern in the east coast gas market, there is a potential for access to processing facilities to become an issue as a result of the bifurcation discussed above.

It is possible that some market participants may need to access the MPH to process gas to the LNG specification. The MPH is owned by a joint venture between Santos, Origin Energy and Beach Energy. It is a large and complex piece of infrastructure, which has seen substantial investment in additional processing infrastructure over the past few years. Santos has publicly stated a number of times recently that the MPH is 'open for business' and is seeking additional third party gas to process.⁷⁸

Given the infrastructure available at the MPH, it is in a strong position to competitively process new third party gas from the Cooper Basin. However, the Inquiry received evidence that the process for agreeing tolling arrangements and prices at the MPH has been long and complex (partly driven by the need for agreement within the Joint Venture).

New entrants and existing producers have an option of establishing their own processing infrastructure instead of relying on the MPH, but this is partly dependant on gas composition (including any liquids) and the presence of contaminants in their gas reserves.

A bifurcated market between Queensland and the rest of the east coast gas market could potentially place the MPH in an increasingly important position. Any gas flowing north towards Wallumbilla from the Cooper Basin, offshore Victoria and the Northern Territory could effectively be required to be treated at the MPH to meet the LNG specification.

While the MPH owners may have incentives to allow access to the MPH to maximise the utilisation of the processing capacity, they could be in a strong position in a bifurcated market to impose a high processing cost on any participant attempting to ship gas into Queensland.

3.3 Policy decisions affecting the level and diversity of gas supply have the potential to cause significant price effects

As discussed in chapter 2, domestic gas users in the southern states are now likely to have fewer options for supply. This is likely to reduce the competitiveness of supply offers in this region. Pricing outcomes for gas users in the southern states will therefore be critically influenced by the volume and diversity of supply in those states.

There is currently little prospect of a significant increase in supply from the existing production basins in the southern states. Moratoria and other regulatory restrictions in various states are preventing or impeding development of new gas supply (see box 3.1). Unless measures are taken to change the supply outlook in these states, gas users are likely to face uncompetitive pricing outcomes.

78 Santos, 2014 Investor Seminar, 26 November 2014.

Box 3.1: Moratoria and other regulatory restrictions on the east coast

There are significant community concerns related to various aspects of the gas industry across Australia. In particular, these have focused on CSG development, the use of hydraulic fracture stimulation technologies (fracking) and potential impacts on water resources and the environment. There are also wider debates around conflicting land use in the resources sector more generally, including access to leasehold farm land and the future of the fossil fuel sector.

These community concerns have led to Commonwealth, state and territory governments implementing various regulatory measures, with some local governments also supporting the limitation or banning of gas developments in local government areas. In March 2014, the New South Wales Government froze the issuance of new gas exploration licences and undertook to carry out a comprehensive review of existing licences. New regulatory requirements have been put in place for existing licence holders and numerous licences have since been handed back or re-acquired by the government.

The Victorian Government has put in place a moratorium on the granting of new exploration licences for all types of onshore gas (tight, shale, CSG and conventional gas), on approvals for all exploration drilling activities and on hydraulic fracturing. The moratorium affects 10 mineral exploration licences that cover CSG, 11 petroleum exploration permits that cover tight and shale gas and three retention leases that cover tight and shale gas.⁷⁹ The Tasmanian Government has also put in place a moratorium on the use of fracking until 2020. On 4 February 2016, the opposition leader of the Australian Labour Party in the Northern Territory announced that a moratorium on the use of fracture stimulation would be put in place, if his party were elected into government, while his government determined the implications of fracking.⁸⁰

3.3.1 Onshore regulatory restrictions are impeding potential new sources of supply

Given the challenges facing traditional sources of supply and the effect that a lack of competition can have on price, allowing new sources of gas supply to be developed is likely to put downward pressure on domestic gas prices. Governments should take into account that moratoria and other regulatory impediments have the effect of preventing or discouraging such developments and on pricing outcomes experienced by domestic gas users.

The impact of rising domestic prices on industrial users was discussed in chapter 1. Margin reductions for industrial users can typically range from 0.6 to 6.0 percentage points depending on the industry and the level of gas price increases.⁸¹ Further, wholesale gas costs make up 15 per cent to 30 per cent of total residential gas bills⁸² depending on the state. For example, household bills could increase by 5 per cent in New South Wales and 11 per cent in Victoria if wholesale gas prices rose by \$2/GJ.⁸³ As noted in chapter 2, the gains to users from increased competition if alternate, low-cost, competitive sources of supply were developed in the southern states could be as high as \$4 per GJ, or up to one third of the delivered price of gas.

Information provided to the Inquiry indicates that there are some projects in onshore New South Wales and Victoria that have been prevented from being developed by government restrictions on supply. The Inquiry has received evidence of exploration plans that have been put on hold or abandoned as a result of onshore moratoria or other regulatory impediments in these states. For example, Santos' Narrabri project in New South Wales has faced repeated delays as a result of regulatory difficulties. A project by Lakes Oil to extract tight gas onshore in the Gippsland Basin in Victoria through conventional drilling techniques is currently on hold due to the Victorian moratorium. The December 2015 Victorian inquiry into onshore unconventional gas in Victoria

79 See <http://onshoregas.vic.gov.au/regulation/current-status-and-allowable-activities>.

80 'ALP would stop fracking in NT', *NT News*, 4 February 2016.

81 Assuming a starting wholesale price of \$6.00/GJ and a \$2.00-4.00/GJ gas price increase.

82 Oakley Greenwood, *Gas Price Trends Review*, December 2015.

83 Assuming baseline wholesale gas prices of \$5.30/GJ in Victoria and \$7.30/GJ in NSW estimated by Oakley Greenwood (*Gas Price Trends Review*, December 2015).

noted that 'Industrial gas users have signed contracts' with suppliers that are affected by the moratorium.⁸⁴ The Inquiry has also received evidence of industrial customers signing agreements for supply with potential unconventional suppliers in Victoria.

It is difficult to determine the volume of gas supply that is being affected by moratoria and other regulatory restrictions in New South Wales and Victoria. In part, this is because these restrictions prevent exploration and development activity occurring that could help to understand the volume and commerciality of gas resources in those states. Some producers or potential producers have provided evidence to the Inquiry that they consider that there is some further exploration potential in these states that has not occurred due to regulatory restrictions. One estimate of the potential volume of unconventional gas in Victoria and New South Wales is shown in table 3.3. Commercial development of most of this gas is being prevented or restricted by moratoria or other regulatory restrictions in these states. This is a material volume of gas in the context of demand in this region.

Table 3.3 Prospective reserves and resources in New South Wales and Victoria as at 2015

State	Reserves (PJ)	Resources (PJ)	Prospective resources (best estimate) (PJ)
New South Wales	6 823	8 412	14 401
Victoria		2 370	452

Source: COAG Energy Council Upstream Petroleum Resources Working Group Report, Coal Seam, Shale and Tight Gas in Australia: Resources Assessment and Operation Overview, November 2015.

With the development of the NGP, the Northern Territory represents a potentially large source of long-term supply for the east coast gas market. As discussed earlier, the Northern Territory Government estimates that there may be in excess of 200 000 PJ of unconventional shale gas in the Northern Territory. While the Northern Territory does not currently have a moratorium on unconventional gas exploration or development, some companies are currently scaling back 2016 exploration projects, blaming the uncertainty caused by the potential introduction of a ban on the use of hydraulic fracturing announced by the leader of the opposition.⁸⁵ This will slow down the appraisal and development of significant potential gas resources which could contribute to future gas supplies for the Northern Territory and the east coast gas market.

The Inquiry acknowledges that there are serious concerns in the community regarding the potential environmental effects of unconventional gas exploration. While recognising the strengths of concerns, the Inquiry encourages the relevant governments to take into account the impact that moratoria and other regulatory restrictions may have on domestic gas users when conducting the cost-benefit assessment of the environmental regulatory regimes. The Inquiry also encourages governments to consider adopting regulatory regimes that allow them to manage the risks of individual gas developments on a case by case basis rather than regimes that impose a blanket moratorium or other regulatory restrictions on gas exploration and production.

3.3.2 Market developments compel the ACCC to revisit GBJV joint marketing arrangements

BHP Billiton and Esso Australia have been jointly producing and selling gas from the Gippsland Basin for nearly 50 years. These producers contend that until the east coast gas market is sufficiently mature, joint marketing is necessary to ensure that the joint venture partners continue to make the investments required to sustain the development of Gippsland Basin reserves.⁸⁶ The producers contend that in the absence of more mature markets, significant investment in new production, which is of higher risk and lower resource quality, may be deterred if gas from those new investments is separately marketed.

⁸⁴ Parliament of Victoria, *Inquiry into onshore unconventional gas in Victoria*, December 2015.

⁸⁵ ABC Rural, 'Jobs leaking from oil and gas exploration sector as Northern Territory debates fracking moratorium', 2 March 2016.

⁸⁶ Esso Australia, *Submission to East Coast Gas Inquiry Issues Paper*, 1 July 2015 and BHP Billiton, *Submission to East Coast Gas Inquiry Issues Paper*, 7 July 2015.

The ACCC conducted a preliminary review of the GBJV joint marketing in 2010, primarily to determine whether the joint marketing arrangement had, or was likely to have, the effect of substantially lessening competition in any market in contravention of s. 45 of the *Competition and Consumer Act 2010* (Cth). The ACCC decided to take no further action at that time, but advised the joint venture partners that it might revisit the matter if future market developments warranted doing so.

The ACCC has not conducted an investigation of joint marketing by the GBJV for the purposes of s. 45 of the CCA as part of the Inquiry. However, due to significant market changes since the ACCC last considered arrangements in 2010, the GBJV now holds significant market power in the southern states (as discussed in chapter 2). The Inquiry considers that joint marketing by the GBJV may now have a more detrimental impact on competition than in the past and warrants reconsideration at the conclusion of the Inquiry.

In considering whether the joint marketing arrangements of the GBJV substantially lessen competition, the ACCC will consider whether separate marketing would give a substantially better competitive outcome to the market. The ACCC will review the joint marketing arrangements in the context of gas which is currently committed for production as well as production from future investment.

The ACCC's assessment will include consideration of the likely effect of separate marketing on future investment to ensure that any potential gains from competition are not offset by the reduction of gas supply from under-development of the Gippsland Basin resources. In this regard, the ACCC will consider whether arrangements could be put in place to enable an individual joint venture partner, potentially in conjunction with other parties, to invest in new projects in the Gippsland Basin when the joint venture partners are not aligned on future investment decisions.

The ACCC will also consider whether the gas market is now sufficiently mature to support separate marketing in light of the changes that have taken place since 2010. There has been a significant shift in marketing arrangements amongst the gas producing joint ventures in Australia. The North West Shelf Gas Project and Gorgon Gas Project in Western Australia as well as Cooper Basin joint venture in central Australia have commenced separately marketing their share of uncontracted gas.

While the specific circumstances of the GBJV will need to be considered, separate marketing by the Cooper Basin joint venture producers in particular provides a positive sign that it is possible to implement balancing agreements between joint venture parties in the east coast gas market and that separate marketing does not necessarily lead to reduced investment in resource development.

3.3.3 Gas reservation policies would reduce the likelihood of new gas supply sources being developed

Some stakeholders have suggested that governments should implement policies to reserve gas for domestic use. These policies could be a variation on three basic options:

- a percentage share of gas reserves or production that must be placed into the domestic market
- a reservation of specific acreage that can only be brought into production for the domestic market
- export controls which require a licence for exporting gas that is granted subject to the application satisfying conditions, such as a national interest test which could include consideration of the impact on domestic supply.

In its 2014 Gas Market Report, the former Bureau of Resources and Energy Economics conducted a detailed analysis of studies that had been conducted in the Australian market relating to reservation policies. This report concluded that in the short term, such policies may reduce gas prices for domestic users as additional gas is forced onto the domestic market above efficient market demand. However, in the medium- to longer-term a number of issues arise which effectively reverse those short-term benefits. In particular, the economic incentives

for further exploration and appraisal activity are necessarily removed with low prices and the effective oversupply of gas. In addition, new gas projects which are scaled to the domestic market may be forced out of the market due to poor economic returns.

Western Australia has a domestic gas reservation policy which seeks to reserve gas equivalent to 15 per cent of gas from new offshore developments to be available for domestic use. This policy was analysed by the Western Australian Economic Regulatory Authority (ERA) in its 2014 *Inquiry into Microeconomic Reform in Western Australia: Final Report*. The ERA recommended that this 'policy should be rescinded as soon as practicable' as it has resulted in the following negative consequences:

- it has increased reliance on subsidised gas prices, leading to over consumption of the resource
- it has inhibited dynamic efficiency and technological innovation
- it has perpetuated the existence of industries that may not have a comparative advantage in Western Australia at the expense of investment in other industries
- it has reduced the incentive for investors to invest in the gas industry in the longer term, leading to potential future gas shortages.

While all of these factors are of concern, the final point is particularly relevant for gas users who will need secure gas supplies not just in the short term but also into the future.

The Inquiry has not identified any market failure in the east coast gas market that would justify the introduction of a gas reservation policy. The gas supply issues that have been identified relate to a structural lack of competition in the southern states. These issues would not be fixed by a reservation policy; in fact they could be worsened if a reservation policy was enacted which artificially depressed prices in the short term and discouraged investment in new gas supply, thus reducing the likelihood of required supply diversity.

4 Risk management mechanisms have become more important and new mechanisms should be supported

4.1 Tightening gas supply has created considerable uncertainty for all gas market participants

The evolving gas market has created new challenges. Producers, retailers and gas users are responding by changing their approach to gas supply contracting. The Inquiry has found that some risks are being shifted from producers to buyers (retailers and other users), and that buyers are having to adopt alternative approaches to manage their exposure.

Most of the increased risks arise from the difficulties involved in predicting future gas prices in an uncertain supply environment. Given rapidly changing market conditions, it is now more difficult to determine whether a particular gas price in a proposed GSA will continue to be in line with the market price for gas over the course of the GSA. This is exacerbated for GSAs with a longer supply length. Also, in an environment of rising gas prices, users are now under greater pressure to manage their gas costs and have a greater desire for volume flexibility, which is becoming harder to obtain. In the face of this uncertainty, users find it harder to make decisions about the future viability of their business, and about future investment decisions.

Some of this increased uncertainty is transitory in nature, arising from the very rapid increase in market supply and demand in recent years. However, given the need for significant continued investment in supply and the risks associated with this (see chapter 3), increased uncertainty about future conditions, including future prices, will continue to be a key feature of the market. Users will be increasingly reliant, directly or indirectly (through a retailer), on mechanisms to cope with risk such as storage and short-term trading to manage this uncertainty. Some large gas buyers may be in a position to hedge oil-linked pricing in their GSAs by participating in international oil trading markets and currency trading markets, but this strategy itself involves a level of future price risk, and other participation costs, that may not be attractive for many gas users.

Retailers are typically in a better position to manage these risks than users, as they are able to diversify their gas portfolio across a number of producers and users. In a market with few suppliers, they are also able to pass the impact of these risks (such as the increasing cost of flexibility) though to users, and are able to make decisions about which customers to supply, based on an assessment of those risks. Accordingly, most of the burden of these risks falls on users rather than on retailers.

4.2 GSAs are becoming less flexible for managing demand risks

4.2.1 The typical duration of a GSA has become shorter

Over the last few years, the typical duration of a newly settled GSA between a producer and a buyer for domestic supply has been no more than three to four years. This is in contrast to large historical GSAs, which frequently had a duration of supply of five or more years. In part, this reflects the lack of new sources of domestically oriented supply being brought into the market. However, another key driver of this reduction in the length of GSAs has been the increased uncertainty over future market conditions, including price, arising from the rapidly changing market dynamics. In addition, some producers have faced uncertainties over future production from their fields, which have reduced their willingness to enter into long-term GSAs.

These uncertainties have affected the willingness of both suppliers and buyers to enter into long-term GSAs at fixed pricing levels, particularly many years prior to the commencement of supply. Given rapidly rising prices, some industrial users have been concerned about the continued

viability of their businesses at higher price levels. This has reduced their willingness to enter into significant, long-term, gas commitments.

Some suppliers have been more reluctant to offer long-term fixed price GSAs at a level that may not be reflective of future market conditions. In part to mitigate the risk of market price changes, some suppliers have sold gas to the LNG projects at prices that are linked to the price of oil. For example, AGL's recent GSA to sell a significant quantity of gas to GLNG, at oil linked prices, has the benefit for AGL of substantially offsetting its oil price exposure under its GSA with the GBJV.

4.2.2 Volume flexibility in GSAs has been decreasing

For producers, the cost of building and operating excess production capacity in order to meet variations in their customers' demand can be substantial.

Where the producer's overall gas production costs are rising, the producer has a greater incentive to reduce uncertainty about cost recovery by offering a flatter load profile. At the same time, producers and buyers each have an interest in obtaining contractual certainty about the peak capacity that the producer will be required to make available at a particular time of the year:

- A retailer needs to know that it will have enough gas available to meet its expected peak demand requirements (such as for winter).
- A producer has an interest in having greater certainty about when the peak capacity will actually be required by the retailer, so that the producer knows when it is likely to be in a position to either use its production capacity to supply other buyers, or to carry out maintenance activities.

The cost for retailers in ensuring that they have access to enough gas in order to meet variations in user demand can also be substantial, as illustrated in case study 4.1.

Case study 4.1: The costs of flexibility

A large buyer of gas for industrial use, such as glass production, experiences a significant reduction in its annual demand for gas but an increase in its daily peak demand requirement and enters into a new GSA with a retailer that reflects this requirement. The new GSA has a lower Annual Contract Quantity (ACQ) and a higher Maximum Daily Quantity (MDQ), which results in a substantial increase in the buyer's load factor.

To ensure that it is in a position to meet the glass plant's peak demand, the retailer may need to reserve additional peak capacity at a gas storage facility. As a result, the charge (per gigajoule of ACQ) payable for that capacity will increase. Even if the per GJ capacity charge payable by the retailer to the storage facility remains the same, the volume of capacity that must be reserved to meet the peak will be higher. The retailer must then recover the increased capacity charge across a substantially reduced ACQ under the GSA, which will result in a higher per GJ of ACQ charge payable by the glass manufacturer.

Historically, many GSAs gave customers a significant degree of flexibility in the volumes that they were committed to take under that GSA. This flexibility was provided in a number of ways, most commonly through take-or-pay provisions, load factor and banking rights (see box 4.1). The Inquiry has found that the amount of flexibility being provided to users in new GSAs has been decreasing in recent years, as the market responds to changing conditions. While some flexibility may still be available, it is at a higher price than it was historically. This has had the effect of shifting the risks and costs of providing such flexibility from producers to retailers and users and has prompted some retailers to seek out other sources of flexibility (such as storage).

Box 4.1: GSA flexibility terms

Take-or-pay multiplier. This is the minimum proportion of the GSA's ACQ that the buyer is required to take in a particular year. The buyer is required to pay for this minimum volume of gas regardless of whether they use it. The take-or-pay multiplier is expressed as a percentage. For example, for a three year GSA with an ACQ of 10 PJs and a take-or-pay multiplier of 80 per cent, the buyer would be required to take at least 8 PJs of gas in each of the three contract years.

Load factor. The load factor (sometimes referred to as swing factor) measures the extent to which a buyer can take more than the average daily contract quantity (the MDQ) throughout the year, subject to the cap imposed by the ACQ being met. For example, under a GSA with an ACQ of 3.65 PJ (equivalent to 10 TJ per day) and a load factor of 1.25, the buyer would be able to take up to 12.5 TJ of gas each day. Having a higher load factor does not increase the quantity of gas that the buyer can purchase in a year. Instead, it provides the buyer with greater flexibility to manage demand variations throughout the year.

Banking rights. Some GSAs for supply over a number of years permit buyers that purchase less than the minimum take-or-pay quantity in a particular contract year to 'bank' that gas and take that quantity at a later time. There are a number of different ways that banking arrangements can operate, including in relation to the price of the banked gas and how or when banked gas can be taken.

In a situation where customers have a contractual right to significantly vary their daily volumes within a year, producers need to maintain excess production capacity to be in a position to supply up to their maximum exposure. Therefore, reducing contractual flexibility allows producers to maximise their overall production of gas across a year without investing in additional processing equipment.

More generally, the reduced flexibility is a response by suppliers to changing market conditions. As gas prices have increased, the opportunity cost of providing flexibility has also increased. Retailers are also passing on the increasing cost of flexibility to their customers. However, buyers are less willing to pay a price that reflects that opportunity cost. The reduced flexibility may also be due to the changes in competitive dynamics discussed in chapters 2 and 3. In the southern states, for example, buyers have fewer alternatives to GBJV gas than they did in the past. This has allowed the GBJV to tighten its conditions of supply.

The Inquiry has observed that, overall, flexibility under new GSAs is lower than has been previously offered and that flexibility is more expensive. The reduced flexibility has occurred in a number of ways, including an increase in the take-or-pay multiplier, a reduction in the load factor, GSAs being offered with a defined load profile throughout the year, and the removal or limiting of banking provisions in new GSAs. In some circumstances, suppliers have significantly increased the cost of providing contractual flexibility to buyers, including by seeking higher per GJ gas prices in return for lower take-or-pay commitments and higher load factors.

For example, of the five domestic GSAs entered into over the last three years that replaced existing GSAs between the same buyer and producer combinations:

- five had a lower load factor than the GSAs they replaced (100 per cent vs 125 per cent–320 per cent), though several of these GSAs have a defined load profile for each month which provides some intra-year flexibility
- three had a higher take-or-pay multiplier (90–100 per cent vs 80 per cent) and more restrictive banking rights than the GSAs they replaced.

There are several new GSAs that have a load factor of 100 per cent and a take-or-pay multiplier of 100 per cent. In effect, the buyers under these GSAs do not have any flexibility to vary their actual gas usage from day to day without having to pay for unused gas under the take-or-pay provisions. They therefore incur costs for unused gas in the event of a planned or unplanned outage.

For buyers, decreased contractual flexibility increases the financial impact of unexpected demand fluctuations, for example, an industrial gas user losing a large customer. If a buyer is unable to meet their minimum take-or-pay commitment and is required to pay for gas that they do not use, the overall effect is to increase their average price of gas. An increase in the take-or-pay multiplier from 80 per cent to 90 per cent deprives a buyer of 50 per cent of the flexibility that was previously available to them.

Some GSAs with retailers also include exclusivity provisions which limit the buyer's ability to obtain cheaper gas from elsewhere if market prices decline. Some exclusivity provisions only relate to particular premises, with the aim of ensuring reliable metering of the gas supplied at each delivery point.⁸⁷ Other exclusivity provisions are an alternative way of reducing the risk that a buyer will not take some or all of the gas available to it under a GSA. Again, there is a trade-off between take-or-pay provisions and these exclusivity provisions—the lower the take-or-pay provision, the greater the likelihood that the supplier will require an exclusivity provision as well, in order to reduce that risk.

Another way in which GSAs address supply risks is through provisions that set out the liability of the supplier for failing to fulfil its obligations to supply gas. These provisions typically require the supplier to compensate the buyer for any shortfall, up to an agreed liability cap. The Inquiry observed that one major supplier had reduced the maximum amount that it would be liable for in the event of failure to supply in GSAs offered in recent years. This supplier stated that this trend was a response to changes in competitive conditions. While not all suppliers have done so, this contractual clause appears to be another way in which supply risks can be shifted from suppliers to buyers in tight market conditions with few suppliers. In some cases, the level of compensation may be so low as to provide an insufficient deterrent to a breach of the GSA by the supplier.

4.2.3 The ability to sell gas to third parties is valuable both for suppliers and for buyers

The standard GSAs of some retailers contain a provision that prohibits the user from reselling gas obtained under that GSA. If the GSA does not include a take-or-pay provision, the restriction on resale deprives the user of the flexibility to deal with that gas as it sees fit, but does not create significant additional risks for the user. In that case, the user is only required to pay for gas that it consumes.

However, the combination of a take-or-pay provision and a resale restriction creates significant additional risks for the user, because if the user cannot meet its take-or-pay commitment due to an unexpected demand fluctuation, the user will need to pay for gas that it does not need and is prevented from selling that gas to a third party. These resale restrictions prevent users from taking advantage of the STTMs, the DWGM and the Wallumbilla GSH to sell excess gas. Apart from limiting the options available to these users to manage their risks, these restrictions also inhibit competition, and the development of liquidity in those markets, by reducing the number of parties using the market and, potentially, the traded volume of gas.

Not all GSAs have resale restrictions. Some end users have been taking advantage of their flexibility under such GSAs to engage in short-term trading strategies to help them minimise their total cost of gas (see case study 4.2).

⁸⁷ In practice, however, these clauses have a broader effect, as it is possible to have more than one delivery point at a particular premises.

Case study 4.2: Short-term trading strategy

A user in a STTM region has been faced with rising gas prices, and experiences significant fluctuations in its daily gas volume requirements that are not easy to predict.

The user has entered into a GSA with a retailer at a price of \$5 per GJ. The GSA has an ACQ and take-or-pay obligations, however, the user has some flexibility to adjust the volumes that they take under the GSA on a daily basis.

On days where the user expects the market clearing price to exceed \$5 per GJ, the user offers to inject gas into the STTM in excess of its own requirements. On days where the user expects the market clearing price to be less than \$5 per GJ, the user bids to withdraw gas in excess of the volume of gas (obtained under the GSA) that the user offers to inject on that day.

Subject to the user meeting its obligations in relation to its contractual volume specifications, this method of participating in the STTM allows the user to obtain cheaper gas when the STTM price is lower than \$5 per GJ, and to sell surplus gas when the STTM price is higher than \$5 per GJ. The user's experience is that this strategy has lowered its overall gas costs.

While this strategy has benefits for the buyer, it creates some costs for the supplier. Pricing offers to major users are often based in part on a forecast of the user's expected demand profile. If the user varies from this demand profile, then it could create additional costs for the supplier to the extent that those costs are not reflected in take-or-pay requirements or in capacity charges, either because the customer's usage is higher than expected (requiring the retailer to provision additional gas and transportation volume) or lower than forecast (meaning the retailer may have excess gas or transportation capacity).

In addition, the option of being able to engage in short-term trading strategies, or of otherwise being able to sell gas to another customer with a flatter load profile, is valuable to suppliers. Allowing customers to engage in the trading strategy as described above prevents the supplier from being able to trade those volumes of gas in the STTMs itself, or to otherwise sell that gas to a third party.

These reasons provide some explanation for why suppliers may wish to include resale restriction clauses in retailer GSAs. The Inquiry was provided with evidence that some suppliers would allow customers to request removal of a standard resale restriction clause but that this would result in a higher price for the supply of gas under that GSA.

The costs described above only arise in GSAs that allow the customer some volume flexibility. In GSAs with a 100 per cent take-or-pay multiplier and which permit no daily variation in volume, and in the absence of a broader commercial relationship between supplier and buyer, it is hard to see a bilateral commercial rationale for inclusion of a resale restriction if the customer wishes to have the ability to resell gas supplied under it. The effect of such provisions is to reduce the potential for the trading of gas to occur.

The Inquiry encourages gas suppliers and buyers to consider ways in which GSAs could allow greater flexibility for gas trading. There would also be merit in the AEMC giving further consideration to whether there might be ways of monitoring changes in the level of trading flexibility available to gas buyers over time. For example, one possible alternative to resale restrictions and exclusivity provisions would be to include profit sharing mechanisms in those GSAs that do allow for volume flexibility. A supplier and a buyer could agree that if the buyer (at the buyer's choice) resells gas supplied under the GSA, it would share a proportion of its profit on that sale with the supplier. In addition, it could be agreed that if the buyer (at the buyer's choice) obtains other gas, it would share a proportion of its profit (that is, the difference between the cost of obtaining gas from the supplier and the cost of obtaining that traded gas) with the supplier.

A contractual mechanism of this kind would give suppliers a greater incentive to allow trading by buyers, as the supplier and the buyer would share the benefits of subsequent fluctuations in

the market price of gas. The Inquiry has observed that there are some GSAs involving Australian suppliers which have profit sharing arrangements where gas supplied under the GSA is resold by the buyer. As an alternative to resale restrictions, contractual implementation of commercial profit sharing arrangements of this nature could potentially assist in the development of liquidity in STTMs, by facilitating the participation of additional buyers in those markets and increasing the volume of gas traded on them.

4.3 Storage facilities have an increasingly important role to play in managing demand risks

Another option that gas market participants have for dealing with variable demand is storage, so that gas does not have to be consumed as soon as it is produced. A map of storage options in the east coast gas market are shown in figure 4.1 and existing storage facilities are described in more detail in table 4.1.

There are three types of storage available in the east coast gas market:

- large longer-term storage facilities located close to gas fields in Queensland, Victoria and South Australia, using depleted gas fields.
- smaller seasonal or peaking storage facilities (including the Dandenong LNG storage facility) located close to gas demand centres in Victoria and New South Wales.
- short-term peaking storage services on gas pipelines.

Table 4.1: Existing storage facilities (excluding pipelines)

Storage Facility	Operator	Withdrawal Capacity (TJ/day)	Storage Capacity (PJ)
Moomba (South Australia)	Santos	80+	85
Ballera (Queensland)	Santos	40	10
Roma (Queensland)	GLNG	75	50+
Silver Springs (Queensland)	AGL	30	35
Newstead (Queensland)	Armour Energy	8	2
Iona (Victoria)	QIC	500	22
Dandenong LNG (Victoria)	APA	158	0.7
Newcastle LNG (New South Wales)	AGL	120	1.5

Sources: Core Energy Group, *Gas Storage Facilities, Eastern and South Eastern Australia*, February 2015, p. 9, and Australian Energy Market Operator, *Gas Processing, Transmission and Storage Facilities*, 9 April 2015.

Storage capacity in Queensland or South Australia can be used as a strategy for managing various types of fluctuations in gas production and gas demand. There is less gas storage capacity available in Victoria and New South Wales. The Victorian and New South Wales facilities, by themselves, are not capable of meeting the entire winter seasonal peak in those locations, as that peak lasts for several months. Thus, retailers in the southern states have to rely on a combination of increased seasonal production by producers, and on that gas storage capacity, in order to meet high winter demand. Retailers in the southern states also use storage capacity on gas pipelines to manage the highest days of peak winter demand.

Figure 4.1: Storage in the east coast gas market⁸⁸



As contractual flexibility is declining or becoming more expensive, storage is becoming more important as a risk management mechanism for gas buyers that have variable loads, particularly in Victoria, New South Wales and South Australia. This is being reflected in moves by some large buyers, particularly retailers, to secure storage capacity. For example, AGL has recently built the Newcastle LNG storage facility in New South Wales, and has also entered into a contract with QIC which entitles AGL to use approximately half of the current capacity of the Iona facility in Victoria from January 2021. In entering into this contract, AGL noted that it will result in a⁸⁹:

88 Core Energy Group, *Gas Storage Facilities, Eastern and South Eastern Australia*, February 2015, p. 8. The Newcastle Liquefied Gas Storage Facility is now operational.

89 AGL media release, 'AGL secures long-term gas storage rights', 1 December 2015.

“...30 per cent reduction in AGL’s costs to manage seasonal demand when compared to AGL’s equivalent contracted costs prior to the commencement of this increased contracted capacity...”.

The high price that QIC paid to acquire the Iona underground storage facility⁹⁰ is another indicator that the demand for storage services is expected to increase in the future. There are several options for developing additional gas storage capacity in Victoria including using gas fields that might become fully depleted in the medium term.

Most non-pipeline storage capacity in the southern states is held by major retailers, although some capacity in Victoria is also held by smaller retailers. Various smaller retailers have obtained storage capacity on gas pipelines, either via the construction of additional ‘branch’ capacity, or as park services on the primary pipeline. Most major retailers also have some park services on these pipelines.

Pipeline operators can also build additional storage capacity, as an offshoot from a pipeline, to provide dedicated storage services to one or more retailers. As this ‘branch’ capacity is not used to transport gas from a receipt point to a delivery point in another location, using this capacity for storage does not involve any loss of transportation capacity for pipeline operators. In contrast, providing park services on the core pipeline itself has the effect of reducing the transportation capacity of the pipeline. This contributes to higher prices for those park services.

Access to storage may become a more significant issue in the future if the volume of gas available for supply into the domestic east coast gas market increases. A lack of access to longer-term forms of storage may constrain the ability of some smaller retailers to expand in the future. Access to storage may well also become an important factor in the development of gas trading. It would provide an alternative mechanism for parties to gas futures contracts to ensure that there is sufficient gas available to them to physically deliver gas, if needed, under those contracts. At present, however, there is no evidence that access to storage capacity on reasonable terms is a significant barrier to entry by smaller retailers in the east coast gas market.

4.4 Liquidity in trading markets is currently limited

There are a number of ways in which participants in the east coast gas market can trade gas on a short-term basis. These mechanisms include the DWGM operated by AEMO in Victoria, the STTMs operated by AEMO in Adelaide, Brisbane and Sydney, the Wallumbilla GSH and bilateral contracting. The AEMC is also proposing a Wallumbilla-style gas supply hub for Victoria, as part of the AEMC East Coast Gas Market Review, and AEMO is planning to establish a trading hub at Moomba. All of these mechanisms can assist market participants to manage fluctuations in gas supply and demand within their own portfolios. The effectiveness of these mechanisms as trading platforms depends, to a significant extent, on their level of liquidity.

Many market participants have raised concerns about the level of price transparency in the east coast gas market. This is because most gas is consumed under long-term, bilateral confidential GSAs. If more gas trading occurred through the STTMs, the DWGM and the Wallumbilla GSH, then this would improve price transparency. If liquidity in these markets was sufficient, the prices established via these trading mechanisms would potentially be adopted as part of a pricing formula under long-term GSAs.

Evidence presented to the inquiry is that these existing trading mechanisms do not currently have sufficient traded volumes to enable a significant number of users to rely on them for obtaining all, or a substantial portion of, their gas requirements via trading. In addition, these mechanisms do not currently provide an adequate price signal to be used as part of a pricing formula under long-term GSAs. While changes to market design may help improve the operation of these markets, without increased volume and diversity of gas suppliers in the market, these mechanisms will have only limited success in providing flexibility and price discovery.

⁹⁰ ‘CLP Holdings sells Iona gas plant to QIC Ltd for \$1.78 bn’, *The Australian*, 8 October 2015.

The Inquiry supports the AEMC's wide consideration of market participant views on the appropriate number and type of trading markets (that is, voluntary or mandatory). The AEMC should test whether other arrangements would be likely to generate more liquidity compared to the existing DWGM and STTM arrangements.

4.4.1 The short-term markets establish prices that reflect short-term fluctuations only

At present, all gas supplied in the Declared Transmission System in Victoria has to be cleared through the DWGM while all gas supplied in the greater Sydney, Brisbane or Adelaide regions has to be cleared through a STTM. The DWGM and the STTMs are mandatory scheduling and balancing mechanisms. Although there is scope for gas to be traded via the DWGM and the STTMs, most retailers and users choose to limit exposure to the market-clearing price by making offers and bids at volumes and prices to 'target' a net sell or buy position of between five to 15 per cent, or in some cases zero.

Accordingly, trading on the DWGM, or on the STTMs, currently only involves a relatively small proportion (10–15 per cent) of the gas that is bought and sold in the geographic regions served by those mechanisms:

- The Victorian DWGM has seen 10 or more active suppliers and buyers over an extended period. Net of matched supply and demand, about 5–15 per cent of total market demand (up to 1200 TJ per day) is traded daily. No ASX derivatives market has developed despite a product being offered since approximately 2010.
- The number of suppliers and buyers in Sydney (total volume 350 TJ per day) has increased recently to 10 or more, and net trade volumes are similar to Victoria (10–15 per cent). The Adelaide and Brisbane STTMs are smaller (total volumes up to about 125 TJ per day), with less net trade typically than other STTMs, particularly in Brisbane. There is no ASX product for the STTMs.

The Inquiry is aware of a couple of examples of participants in the east coast gas market using the existing DWGM and/or the STTMs to support their gas volume requirements either in part (see case study 4.2), or in whole (see case study 4.3). These strategies are most attractive to buyers who have significant flexibility in their day to day gas demand requirements. Many gas users have limited short-term flexibility in their gas demand, which limits the appeal of these strategies.

Case study 4.3: Small retailers

Some small gas retailers have been obtaining gas by bidding to withdraw gas from an STTM, without also offering to inject gas into the STTM. That is, these retailers obtain all the gas that they need in the relevant STTM region at prices determined on the STTM, rather than via a GSA.

This enables the retailer to enter or expand its market share without needing to commit to a longer-term gas supply arrangement with a producer or a retailer. Although the retailer is exposed to fluctuations in the STTM price, the retailer can try to manage this risk either by offering retail GSAs which 'pass through' the STTM price, or by entering into demand management arrangements with their customers whereby customer usage is reduced at the request of the retailer when STTM prices are high. These types of retail offers may be attractive to industrial customers that have a significant degree of flexibility in their gas usage.

In addition, many parties indicated to the Inquiry that the price of traded gas is considered to be volatile. There is a risk of large fluctuations in the price and volume of gas available from day to day. This lack of commercial certainty acts as a strong disincentive against increased reliance on gas trading, both by producers and by users.

A key way of measuring liquidity in trading markets is to assess whether market participants have the ability to execute trades without having a material impact on price. As noted above, based on evidence available to the Inquiry, the volumes of gas currently traded on the DWGM

and on the STTMs would only support a limited number of buyers using those mechanisms as their primary source of gas. A significant increase in the number of buyers engaging in these types of strategies would lead to a significant increase in the price of gas traded via those mechanisms. This indicates that these markets are not deep, which discourages more extensive reliance on these markets as a source of supply. Although a significant increase in a DWGM or STTM price might potentially lead to additional supply by producers and/or retailers via that mechanism, it is also likely to lead to reduced demand by existing buyers who also have the option of obtaining gas under a GSA. Thus, the overall effect on liquidity is likely to be muted unless the increase in the volumes sought by non-GSA buyers is very large.

No producer currently uses the DWGM or the STTMs as a major outlet for supply. The vast majority of gas produced in the east coast gas market is sold by the producer under bilateral GSAs. Such GSAs have historically been an important tool to underpin new investment in gas fields as they give price and demand certainty to the producer. Producers provided evidence to the Inquiry that they did not have sufficient confidence in the maturity of STTMs to provide them with a level of price and volume certainty that would enable them to supply significant volumes of gas on these markets. Similarly, many buyers are concerned that trading gas will increase, not decrease, their overall average gas price if demand on the DWGM or STTMs increases significantly.

Almost all market participants who provided evidence to the inquiry on the STTMs indicated that they considered these markets to be primarily 'balancing' markets rather than full trading markets. Most of the traded volumes were to adjust imbalances between expected and actual supply or demand and the prices only reflect short-term day to-day-conditions, rather than the underlying supply and demand conditions for gas supply. The short-term prices in these markets were not regarded as providing a guide to actual market prices which could be reflected in bilateral supply negotiations.

4.4.2 The Wallumbilla GSH is currently attracting a limited range of participants

The Wallumbilla GSH is a voluntary exchange that enables suppliers and buyers to trade gas up to several months in advance of physical supply. Specific offers and bids are anonymously matched against each other, on a bilateral basis, to form a trade. The exchange does not determine a market-clearing price applicable to all participants.

Trade at Wallumbilla has been increasing but is still intermittent—there have still been some days on which no gas has been traded. An ASX derivative product was launched in the middle of 2015, but there have been very few trades of this product as yet. Registered participants on the Wallumbilla GSH include producers, large retailers, GPGs and three large industrial users.

The Queensland LNG projects provided evidence that they have a significant interest in being able to engage in short-term trades to manage unexpected variation in production and LNG plant performance. APLNG, for example, has been active on the Wallumbilla GSH in the past 12 months. However, the LNG projects indicated that to date the vast majority of their short-term trading has been undertaken by way of flexible bilateral gas supply arrangements. These participants indicated that this was because there were only limited volumes traded on the Wallumbilla GSH.

Compared to current levels, the volume of trades on the Wallumbilla GSH should increase over time as the LNG projects move into full production and become more focused on developing and optimising their supply operations and trading strategies. In addition, if the LNG projects engaged in fewer bilateral trades to manage their volume fluctuations in favour of using the Wallumbilla GSH this would, over time, increase the volumes traded on the hub.

However, producers might be reluctant to do this due to the urgent nature of many volume fluctuations (for example, unexpected infrastructure failure), which means the consequences of being unsuccessful in clearing a trade in a short time horizon are very severe. The LNG project participants often also have other physical mechanisms available to them for managing fluctuations, including turning down the flow of gas from their wells and access to nearby storage facilities. In addition, even though trades on the Wallumbilla GSH are anonymous, other

market participants may be able to infer the identity of particular bids given the low frequency of trade. Market participants may be reluctant to provide other parties with such market intelligence by trading on a public hub.

4.4.3 Greater liquidity in trading markets is desirable but is dependent on increased participation in markets

There is merit in encouraging greater participation in wholesale gas markets as a way of increasing liquidity which will improve price discovery and better allow market participants to manage volume fluctuations. The Inquiry supports the development of trading mechanisms that are targeted at facilitating greater participation in trading markets. Being able to manage volume fluctuations on trading markets could help users compensate for a reduced level of contractual flexibility in recent years. Establishing a reliable trading price would provide greater clarity for producers in making production and pricing decisions, potential new entrant retailers in making their entry decision and users, including commercial and industrial users, in making long-term business planning and investment decisions.

To increase participation in trading markets, steps can and should be taken to reduce the costs associated with trading in those markets, including the costs of transporting gas to them (see chapters 6 to 8). In the long-run, however, significant improvement in participation and liquidity will be best supported by an increase in the diversity of gas market participants and the volume of gas supply in the market.

4.4.4 Reducing transaction costs will increase participation

The greater the costs and difficulties of participating in trading markets, the more users will be reluctant to engage in trading activity. The following steps could be taken to reduce transaction costs in trading markets:

- align the gas start of day in each trading market
- align gas supply nomination times across producers and align gas transportation times across pipelines
- improve the ability of market participants to access short-term pipeline capacity by standardising contract terms and conditions and other potential measures such as auctioning of capacity
- ensure that alignment and risk issues (including the risk of incurring ancillary charges associated with particular market mechanisms) are taken into account when designing or re-designing derivative trading products, such as those offered by the ASX in relation to the Victorian DWGM.

The Inquiry understands that the AEMC is considering each of these matters as part of the AEMC East Coast Gas Market Review and the Gas Day Harmonisation proposed rule change, but that matters such as aligning nomination times across producers and pipelines may need to be an industry led initiative. The Inquiry supports the AEMC's efforts in this area, and encourages industry to do its part to reduce any potential barriers to trade and transaction costs. There would also be merit in the AEMC considering how the trading and other risks of purchasing gas and transportation services on a day-ahead basis can best be managed, given the potential in some cases for:

- the buyer to have to purchase gas from the trading market without knowing if it can secure transportation services
- the buyer to have to make nominations to producers or pipeline operators for the following day without knowing the ex-ante STTM price for that day
- a peaking GPG to have to purchase gas for the following day without knowing that the electricity it intends to produce using that gas will be dispatched.

4.4.5 Increased volumes and diversity of supply

Table 4.2 summarises the factors identified by the Inquiry that are relevant for assessing whether trading markets are well functioning. An improvement in these indicators will increase the confidence of participants in trading markets and improve liquidity.

Table 4.2: indicators of confidence in gas trading markets

Indicator	Current status	Future outlook
Minimal price change in response to trade (market depth)	Small increases in volume lead to large changes in price	If supply outlook improves and confidence in market increases, the proportion of gas supply traded as spot may increase
No dominant trading party	Small number of parties account for vast majority of traded volumes	More participation from the LNG projects or new small users and retailers may increase diversity of participation
Large number of producers and buyers	Small number of producers, particularly in the southern states; the three largest retailers account for a significant proportion of retail gas markets	New sources of supply in the east coast gas market may increase diversity of participation
Available commodity	Market supply is tight during ramp up to full LNG production	Possible improvement in supply conditions as LNG projects reach steady state and if gas from Arrow's fields and/or Northern Territory gas are supplied into the market
Available transport	Market has been adjusting to new LNG-led supply dynamics; contractual congestion on some routes; difficulties in short-term trading due to high transaction costs	Market adjusts to new dynamics; possible introduction of auction mechanism to facilitate short-term pipeline capacity trading

While the status of many of these indicators is such that many users do not have a high degree of confidence in trading markets, there is some hope that the situation will improve in the future. In particular, increased participation by LNG projects in trading markets over time has the potential to lead to material increases in liquidity, particularly once they reach full production and start to optimise their supply operations and trading strategies.

Trading on the Wallumbilla GSH may provide a mechanism for additional gas to enter the domestic market, if the LNG projects become net suppliers into the Wallumbilla GSH once they enter full production. However, this effect may be muted by the fact that additional supply into the Wallumbilla GSH may reduce the price of gas on the Wallumbilla GSH, in the absence of a corresponding increase in demand. LNG projects might also decide to sell gas directly into the southern states, including any future trading hub in the southern states if they are able to access transportation capacity on reasonable terms.

As discussed in chapter 3, the likelihood of additional gas entering domestic markets at any particular point in time will depend on the current and expected future dynamics of LNG export prices and the extent to which the LNG facilities are operating at full capacity. Access to LNG export prices, and the distance from demand centres in the southern states reduces the attractiveness for the LNG projects of transporting and selling their own gas into the southern states. However, there is some evidence (see chapter 8) that flows of gas from Queensland into the southern states, including via swaps, may increase to some extent in the future once the LNG projects reach steady state production. The availability of additional gas for domestic consumption in Queensland may also free up other gas for retailers to supply into the southern states.

In addition, as discussed in chapter 3, improving the supply outlook in the southern states through the removal of restrictions on onshore gas development has the potential to increase diversity of supply and lead to greater liquidity. Regulatory steps to improve access to short-term pipeline capacity, including as proposed by the AEMC, will also assist participation in these markets.

4.4.6 Establishing a price series would be more effective than mandatory trading

One way which could be seen as improving liquidity would be to require mandatory trading of gas—that is, to require that producers sell gas through trading markets, at prices determined by those markets, rather than under GSAs, or to restrict, in some way, supply under GSAs. The Inquiry does not support such measures.

GSAs play an important role in the market, and will continue to do so. They provide producers with a degree of price and volume certainty, which is necessary to support investment by some

producers. For example, small producers may be able to rely on a committed customer's credit rating when seeking finance. Other producers may be able to accept more risk, but may also be unwilling to fully commit to a very large investment decision without a significant degree of certainty that they will be able to sell the volumes that they produce. GSAs also provide users with a greater degree of certainty about their future gas supply, including about the price that they will pay for gas, which allows them to make investment decisions with better information.

Given the importance of GSAs, restricting the supply of gas under GSAs would cause major disruption to business planning and investment by producers and users until a new supply and demand balance is established, and the eventual pricing outcomes are very difficult to predict. Those outcomes may themselves be affected by reductions in demand arising from that disruption.

Establishment of an off-market indicative price series or price index (see chapter 5) is a more appropriate mechanism for improving gas price transparency. An indicative price series or price index based on LNG netback or GSA prices would provide a mechanism for comparing trading prices with those other prices. It would therefore assist producers and users in deciding whether to commence trading, and to do so at a time that would minimise any disruption to their businesses. If such a mechanism becomes sufficiently well accepted, market participants might decide to make use of that price series as an element of the pricing provisions in a GSA. Supporting this, the Inquiry has seen GSAs that contemplate the possibility of substituting the agreed contract price for an external price if such a price is sufficiently well established.

5 The gas market is opaque and is not signalling expected supply problems effectively

There are a number of general attributes that assist in creating a competitive market that operates efficiently and sends appropriate investment signals to market participants. For a gas market, these attributes include buyers and sellers being able to access consistent information on gas reserves and resources to enable informed decisions related to the supply or use of gas, and an indicative price to provide a guide to the value of gas.

The east coast gas market is lacking in both these attributes. Information on gas reserves and resources is inconsistent, unreliable or unavailable, hindering the market's ability to respond to supply tightness and current and predicted higher prices. An indicative gas price is unable to be calculated by the majority of participants given the confidential bi-lateral contracts which dominate the market.

Informed decisions provide a more certain regulatory environment and assist in encouraging competition, creating more efficient market structures and ensuring that regulatory burdens on industry are non-duplicative and effective. The International Energy Agency noted in its 2012 review of Australian Energy Policies⁹¹ that 'high quality energy data and statistics are the cornerstone of energy policy and an essential element of informed decision making' and that Australia should improve its data gathering. It also assists in providing assurances to the wider community that petroleum resources and reserves are being managed in the national interest.

When relevant information and data is combined with an indicative price reflective of real market prices, it improves the ability of market participants to respond to potential supply shortfalls, infrastructure investment opportunities, and price movements.

5.1 Additional gas market information will improve market competitiveness

A number of users have stated publicly and to the Inquiry that sufficient information is not available to fully inform investment decisions or to provide an equal basis in contract negotiations. This included such information as the availability of reserves and resources information, production profiles for CSG wells, and production and shipping schedules for the LNG projects.

It is important to note that all gas reserves and resources (and petroleum reserves and resources more generally) are not absolute and cannot be measured directly. Estimates of reserves combine information and assumptions about economics, feasible technology and geology. Upstream companies will use this information in different ways when assessing the economic potential of a given resource or reserve, with differing assessments of the potential to deploy technologies in developing gas resources, differing efficiencies companies can bring to bear on the production process and differing views on future demand and price levels.

Not all participants in the gas market will have the same level of information or understanding of the various assessments and judgements used to bring a project into production. However, to use reserves estimates in the making of informed judgements, it is necessary to have some understanding of how they are generated and to have confidence in the integrity of the estimating process.⁹²

Currently, reserve, resource and production information is collected through a range of disconnected mechanisms and bodies. The Australian Stock Exchange (ASX) has a reporting obligation for listed companies to report limited information on gas reserves annually along with quarterly production activities. Companies may provide additional details through investor presentations which are also provided through the ASX. State and territory governments all have

91 International Energy Agency *Energy Policies of IEA Countries: Australia 2012 Review*, p. 11.

92 Oxford Energy Institute Paper at <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/SP17-PetroleumReservesinQuestion-JMitchell-2004.pdf>.

some reporting requirements and the Commonwealth collects some information particularly related to its responsibility for offshore resources, although much is commercial in confidence.

Unfortunately, the way information and data is collected, aggregated and disseminated limits the usefulness of much of the reserve and resource information that is available to market participants and regulators. There is little consistency in data standards and aggregation between jurisdictions and the ASX. Most of the assumptions that lie behind the data are not reported and largely invisible to participants.

5.1.1 Better information and data will benefit all market participants

Consistent, reliable and accurate information, particularly around reserve and resource data, provides a number of advantages and benefits to gas market participants across the value chain. This includes reducing transaction costs in activities such as contract negotiations by providing all parties with a higher level of confidence in negotiated outcomes. It also allows for the implementation of appropriate management strategies proportionate to known risks to be incorporated in these outcomes.

There are also more specific benefits that should assist the downstream, midstream and upstream market participants along with governments and regulators.

- Gas users—Data on reserves and resources assists in informing the decisions of gas users about their future use of gas, forward planning and investment decisions. Additional data and information would also have the effect of levelling the playing field where large incumbents (both producers and potentially aggregators/retailers) have additional knowledge and information not available to most other market participants. This puts gas users at a distinct disadvantage in contract negotiation and bargaining.

Where gas users depend on gas as a feedstock (petrochemicals, fertiliser manufacture) or as a major fuel source (glass, paper, co-generation etc.), a higher element of certainty is required around future gas supplies to underpin large investment decisions on periodic plant refurbishments or major investments in upgrades, expansions or new plant and equipment.

- Pipeline owners/operators, storage owners, processing facility owners—Changes in gas reserve bookings over time would signal future investment opportunities and supply related risks to the midstream transportation and facility owners/operators. This could include maximising the flexibility of existing investments through timely upgrades as new or different types of reserves are brought into production or facilitating new production through timely investments in connecting infrastructure.
- Suppliers and producers (including new entrants)—Additional reserve and resource information coupled with the demand forecasts provide an important investment signal to the upstream sector in pursuing new exploration and development activities. It could also provide increased confidence to the investment community in providing the capital to undertake these activities.
- Government and regulators—A consistent and fuller information suite will provide governments and regulators with a more accurate benchmark on which to formulate policy and regulations for the industry. It would also provide a fuller and more accurate picture of the resource endowment of various jurisdictions and to provide more accurate advice to governments on matters relevant to managing that resource in the interests of the community.

It should also help inform government about the potential costs and benefits of implementing policy decisions like moratoria or changes in regulatory compliance burdens. Concerns about the security of long-term gas supply for industries and households could be weighed more accurately with the concerns of and interests of sectorial interest groups. It would also inform decisions around the necessity of royalty holidays, increased depreciation and tax concessions to stimulate exploration and development if governments were concerned about the adequacy of gas supplies in the future.

5.1.2 Improving Information and data collection and dissemination

A more complete set of information and data especially around gas reserves and resources fits within the National Gas Objective. The National Gas Objective as set out in the National Gas Law is to:

“... promote efficient investment in, and efficient operation and use of natural gas services for the long term interest of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.”

The National Gas Law already provides for certain information to be reported to AEMO for publication on the Gas Market Bulletin Board and the AEMC is currently considering using this power to require the publication of more information on proven and probable reserves.

5.1.3 ASX reserve reporting requirements

Essentially, the reporting rules and guidelines for ASX reporting are based on the Society of Petroleum Engineers-Petroleum Resources Management System (SPE-PRMS). Reporting on reserves and resources is undertaken on a probability basis with a company required to have an economic project to book reserves and resources. However, the SPE-PRMS is a principles-based project management system for petroleum resources and is not in itself a set of reporting guidelines.

Under the SPE-PRMS the following categories for classifying reserves and resources are used:

- Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects.
- Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies, for example, cost, technology, market demand.
- Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions:
 - Proved (1P—90 per cent probability of being produced)
 - Proved and Probable (2P—50 per cent probability of being produced)
 - Proved, Probable and Possible (3P—10 per cent probability of being produced) are the measures of probability used.

The Guidelines for Application of the Petroleum Resources Management System note that ‘It is important to restate the following PRMS guidance: While each organisation may define specific investment criteria, a project is generally considered to be economic if its best estimate (or 2P) case has a positive net present value under the organisation’s standard discount rate.’⁹³This then is the basis for a project (and for companies in assessing the viability of a project). The 2P reserve classification becomes the standard reporting measurement in both external reporting obligations and in internal project investment decisions. Understanding some of the underlying assumptions on how 2P reserve calculations are reached (such as a price assumption) provides additional assurance to market participants on the certainty of projects being able to deliver gas.

5.1.4 Other data sources

The Gas Statement of Opportunities (GSOO) and its related data and information sets are published every year for both the east coast gas market and the Western Australian gas market by AEMO. It provides a range of information on gas reserves and resources coupled with information on processing and transportation infrastructure and demand. The GSOO analyses transmission, production, and reserves adequacy, to highlight locations where forecast growing demand may require investment in new gas production or transmission infrastructure, or field developments.

93 See http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf page 110.

The GSOO does not claim to provide all the information investors and market participants require to make a particular investment or marketing decision. Much of the data in the GSOO is also based on a range of assumptions and information utilised by consultants preparing the report, which while it may be close to actual company information, is based on assumptions and processes that are not transparent to the market and are likely to differ from actual company information.

States, territories and the Australian governments all have access to different data sets which cover aspects of reserves and resource bookings by the industry. There are also significant differences in the public release of that information between jurisdictions.

- Queensland appears to have the most encompassing data collection regime and makes most of the collected data public through a downloadable spreadsheet. Spreadsheets cover both production and reserves for CSG, conventional gas, condensate and oil production.
 - Booked 2P reserves for all permits along with the permit designation and number, the operator, basin and field are all available as is a time series of reserve bookings back to 2005. The reserve bookings are based on SPE-PRMS guidelines but assumptions underpinning reserves are not available.
 - Over time and combined with well data in quarterly reports, this information could be combined to give an indication of production decline rates and well productivity for specific licence areas which may be useful for the market (and regulators).
- South Australia, Victoria, New South Wales and the Northern Territory all appear to have little information available publicly on reserves or resources. Partly this is the result of evolving onshore regulation where until comparatively recently there was limited onshore exploration and development (especially in New South Wales and Victoria).
- The Commonwealth, through the National Offshore Petroleum Titles Administrator (NOPTA) mandates the provision of reserve and production information (along with a wide range of other information) in annual title assessment reports under the Offshore Petroleum and Greenhouse Gas Storage Act. However, the information is regarded as commercial in confidence under the regulations and is not available publicly or to other government agencies.
- The COAG Energy Council has also directed the Upstream Petroleum Resources Working Group to provide a report on unconventional gas reserves, resources and production for Council Ministers. However to date the report has contained significant information gaps where states and territories have been unable to provide information to Geoscience Australia (who compiled the report).

5.1.5 The United States (US) reporting requirements are more comprehensive and consistent

The US reporting regime is useful to examine given some similarities with the gas industry in Australia (both industries operate offshore and onshore, have conventional and unconventional resources and have private companies operating across state boundaries in a federal system).

The US Securities and Exchange Commission (SEC)

The SEC has mandated increased standardisation particularly around a standard oil price assumption. Companies now report using a 12-month average oil price at the end of September each year when reporting on proved reserves. The SEC has optional reporting of proved and probable reserves (1P).

In 2008, the SEC sought comment on the use of oil price assumptions as part of the Modernisation of Oil and Gas Reporting project with a particularly forceful commentator noting that:

“Under no circumstances should individual companies be allowed to generate their own price forecasts for the basic proven SEC reserves report. This will lead to inconsistency, and no one will be able to compare companies ... Use of an average price or SEC generated price deck would lead to consistency between companies.”⁹⁴

The SEC rules require companies to use the unweighted average of the price on the first day of each month for the 12 months preceding the end of the company’s fiscal year.

The SEC has noted that the rules reduce the effects of short-term volatility and seasonality in the market while enhancing comparability between companies, and that they enable investors to compare the business prospects of various companies on a more objective level.

The US Energy Information Agency (EIA)

The EIA also maintains a mandated and encompassing information gathering and release regime. This includes information on oil and gas reserves and resources, production, storage and gas prices.

The information on reserves is gathered through a mandated survey form (Form EAI-23L) which requires detailed information on reserves down to specific fields in each tenement for individual companies across all states in the US. While not all companies report every year, it appears that all larger companies are surveyed and small companies whose reserves are less material for EIA purposes are surveyed less often.

Information is available publicly although reserve information is aggregated to a geographic area level in the publicly available reports.

The EIA releases a large range of information and reports based on this and other data. Most of the supporting data is available for download and public use.

5.1.6 Reporting requirements in Australia are inconsistent and incomplete

While reporting reserves and resources has the potential to provide useful information and to meet the stated objective of providing investment signals, there are a number of inconsistencies in the way this information is currently reported that limits its utility. For example:

- **Reporting dates:** Companies report reserves to the ASX at different times throughout the year with no clear date from which a reserve figure is taken. For example, Santos reports its reserves in February, Origin in July and BHP Billiton in September as part of its annual report.
- **Aggregation:** The ASX provides flexibility in how companies report reserves according to geographic region. The instruction to use ‘arithmetic summation’ according to company-defined geographic areas means that BHP Billiton reports a single figure for all its reserves in Australia while Santos and Origin Energy break figures down into basins. Smaller companies that have fewer projects may have more specific reserve reports.
 - Companies do report further information in a variety of company presentations to investors or other presentations which are usually also available on the ASX.
 - While these presentations are useful, diligence in collecting this information is required for it to be used to put together a reserves picture for a specific company or gas field.
 - Quarterly reports which are also lodged with the ASX provide details on well drilling activity and production. Again there is a great deal of variability in this information between companies. The production figures can be subtracted from reserve figures (if available) to provide an ongoing picture of reserves and field depletion.
- **ASX limitations:** Only companies listed on the ASX have an obligation to report reserve figures. As an example, the half owner and operator of the GBJV-ExxonMobil, only reports its reserve figures to the US SEC. However, these figures are also highly aggregated into

94 See <http://www.sec.gov/rules/final/2008/33-8995.pdf>.

geographic regions and provide little detail specific fields, basins or remaining reserves in the Gippsland Basin.

- **Assumptions:** There is little detail given in the ASX reporting as to the financial and other assumptions that are behind the calculation of a reserve figure. When companies first report on reserves or resources they are required to provide material economic assumptions that underpin the numbers and when there are material changes in reserve or resource numbers these must also be explained.
 - However, in practice the guidelines from the ASX provide a great deal of flexibility as to assumptions that are used in calculating reserves by a 'qualified person' which may then be passed through a reserves committee in the company for a final assessment before being reported. The level of detail which companies provide in reserve and resource reports also varies considerably.
 - Consistent and accurate information including price assumptions would assist the investment sector to better assess project economics, company balance sheets and share price assumptions. This would enable a higher level of confidence by the investment sector in providing finance for the upstream industry with appropriate terms and conditions attached to that finance.
 - The ASX reviewed its reporting rules and obligations in 2013 but at that time elected not to standardise the price assumption reporting. It was reported that smaller companies objected to the standardisation which they believed would disadvantage them—although it is not clear how that disadvantage would occur.

5.1.7 Commerciality concerns unreasonably limit the availability of market information

The upstream industry through its peak body, APPEA, raised the issue of duplication in data collection and concerns over the commerciality of information. The Inquiry does not disagree with this point and considers that streamlining data collection and ensuring that it is consistent, accurate and available to all market participants is important. This should assist in limiting the duplication of information and reduce the likelihood that participants are working with potentially conflicting information and data which has the potential to add considerably to transaction costs in the industry and result in inefficient decision making.

There have also been concerns expressed that the more detailed reserve and resource information may disadvantage companies who are being forced to divulge commercial information to the market place. This was a major concern of Australian companies in providing more detailed information to the ASX on reserves and resources compared to some of the large international companies who are not listed on the ASX and would not have the same reporting obligations.

However, the catch-all of 'commercially sensitive information' appears to have been overcome in some jurisdictions (for example, Queensland) that do publish reserve information regularly and where the upstream sector operates very successfully. In addition, the collection and publication of more detailed information on reserves outside of the ASX obligations would require all companies and entities which operate in Australia to report, not just listed or Australian companies.

5.1.8 There are reforms underway

The ACCC is aware that other bodies are looking at making improvements in this area. For example, the COAG Energy Council is undertaking the development of a *Gas Supply Strategy* as part of its Gas Agenda. A key aim of the Strategy is 'Improving information on gas reserves and production potential'. The Commonwealth is also conducting the *Offshore Petroleum Resources Management Review*. While the review is not aimed primarily at increasing data availability, there is a focus on improving the transparency of decision-making which includes the assessment by regulators of gas tenement information including reserves and resources.

In addition to these distinct work streams, a number of state and territory agencies and departments are working at streamlining and standardising reporting regimes in individual jurisdictions. There are also a number of national and international groupings which periodically examine reserve and resource reporting requirements.

5.2 The lack of pricing information impedes competitive bargaining

It is very difficult for any market participants to determine what a 'fair gas price' means in the east coast gas market. There is little information available that could assist in calculating an accurate indicative price. This lack of readily available pricing information also favours large incumbents (who have multiple interactions across the sector) in price negotiations.

Confidential bilateral contracts continue to dominate the market. The Wallumbilla GSH allows participants to trade gas over longer terms than just a daily imbalance including weekly, monthly and three monthly, using standardised contracts. While there has been a small increase in trades as the LNG projects have commenced production, it remains relatively thinly traded and the prices at the Wallumbilla GSH are not an accurate reflection of a true indicative price.

The STTMs and the DWGM are wholesale gas balancing mechanisms rather than true trading hubs. While a number of participants have indicated to the Inquiry that the STTMs, in particular, are a useful adjunct to their gas buying activities, they have limited utility in providing an accurate indicative price for other market participants or the wider contracting market.

Pricing on the DWGM and the STTMs is limited, in practice, by the fact that most gas users will not be willing to pay DWGM or STTM prices that are higher than the prices payable under existing GSAs. Consequently, daily fluctuations in DWGM and STTM prices only reflect short-term day-to-day-conditions, rather than broader price trends. The DWGM and STTM prices are influenced by GSA prices, but they do not provide a clear guide to actual GSA prices. By their very nature as day-ahead trading mechanisms, they play an important role in revealing actual seasonal and other market variations in gas demand and price. However, they do not provide a mechanism for determining an overall stable and certain gas price to apply between a seller and a buyer over a longer period of time, taking various flexibility considerations (including the particular demand profile of the individual buyer) into account throughout that period.

A lack of pricing information complicates and slows bargaining. Much pricing information is private and particular to specific contracts and negotiations. Because of this there is a large disparity between the level and accuracy of information available to players such as producers and retailers that participate in more trades, are larger, or are more vertically integrated versus players such as industrial gas users who typically are less frequently parties to negotiations and agreements. While some disparity of this sort has always existed, the disparity is worsened during times when the number of offers made by suppliers is reduced. In the situation where few offers are being made, industrial users are less able to use the information that would be embodied in a variety of offers as a substitute for knowledge of recent agreed contracts.

There has been some work to encourage the development of a range of trading products and a gas futures market. However, they are yet to be widely adopted or utilised and are without a useful indicative price and so are of limited use for the market to date.

The AEMC is working on ways to develop a more liquid hub-based indicative price, but this is likely to take some time to emerge. The Australian Bureau of Statistics (ABS) is investigating a gas price index which will track movements in wholesale gas prices rather than the actual price. The number of contracts traded in a time frame and over a given geographic area will dictate the markets that can be represented in the index given the need of the ABS to adhere to its confidentiality guidelines (that is, Australia-wide index vs western/eastern market vs markets by state). This may limit its utility given the significant differences between gas markets.

The Inquiry has therefore considered whether there would be merit in developing and publishing another form of indicative price to enhance price transparency for all participants. Indicative prices would provide greater visibility of producer gas prices and provide a more level playing field for the negotiation of actual commercial arrangements. Responsibility for developing

and implementing any indicative price should be given to a body trusted by industry and with experience in handling, manipulating and guarding the confidential nature of information. A body such as AEMO or the AER, with potential assistance from the ABS, would ensure that an indicative price series is more readily accepted by all participants in the gas market.

The Inquiry has considered a number of possibilities for developing and implementing an indicative price series, including an LNG netback price series and a price series based on the gas prices actually invoiced by sellers to buyers.

5.2.1 Publishing an LNG netback price series will assist price transparency

With the export of LNG to international gas markets, the east coast gas market is now also linked to international gas prices. However, there also appears to be little common understanding of what a netback price means for domestic gas market participants, how it is calculated, and how it should be reflected in the domestic market.

Domestic gas buyers with new contracts are now effectively paying a price influenced by the netback price for LNG in Queensland. The amount that LNG projects are prepared to pay for this gas represents the opportunity cost for other gas producers of supplying gas to domestic users in Queensland, and this is the price users are likely going to pay. A full explanation of the calculation and implications of the netback price was presented in chapter 2 of this report. The Inquiry recommends that AEMO use this methodology to publish a monthly LNG netback price to Wallumbilla, along with a clear explanation of framework and of relevant inputs.

5.2.2 The benefits of publishing an invoice-based price series

During the Inquiry, a number of gas users expressed frustration that there was little or no information with which to benchmark the offers they received and no ability to compare contract terms and conditions.

While there would be some uncertainties and costs that would need to be addressed in developing an indicative price for the east coast gas market, there would be a number of potential benefits for market participants in having access to a volume-weighted indicative price series, based on the prices and volumes actually invoiced by producers:

- It would provide greater visibility of producer gas prices including the most important commercial terms that affect those prices—namely, take or pay percentages and load factors—which are important pricing elements in actual commercial negotiations, but would not set either a ceiling or a floor on those prices.
- It would provide a market reference point to gas users when negotiating GSAs with producers and retailers. This would impose a clearer competitive constraint on gas producers and gas retailers in their supply negotiations with users and may provide a more even playing field during the bargaining process.
- It would provide a mechanism to compare the indicative price based on GSAs with short-term trading market prices over time. If greater liquidity develops in the trading markets and hubs, the need for an indicative price would reduce over time.
- It would provide a market reference point for smaller and new entrant gas producers on which to benchmark the potential prices they may receive in developing new gas supplies. This would also apply to the financial sector which has an interest in assessing the ongoing viability of new and existing gas projects.
- It would enable the monitoring of GSA prices and changes in GSA terms and conditions over time. The Department of Industry, Innovation and Science recently engaged a consultant to provide a price trends review which commenced this process. A more transparent indicative price would allow a more accurate continuation of this work along with a range of assessments by governments and regulatory bodies with an interest in maintaining a competitive market.
- An indicative price based on all producer prices, rather than on selected user prices, and compiled on a commodity basis rather than on a delivered basis, would be less affected by variables such as transport costs, or by decisions by retailers to favour supplying some

classes of customers over others. The widespread presence of oil-linkage in producer contracts means that changes in the oil price would be reflected in an invoice-based indicative price over time.

5.2.3 Difficulties in calculating an invoice-based indicative price series

There is a range of views about how long the current market conditions of supply and price uncertainty will continue. There was a view that once the LNG projects reached a steady state of production, the market would return to a state of equilibrium albeit with higher gas prices.

Given current events in the oil and gas industry internationally and the ramifications that are playing out in Australia, this appears less likely. The disequilibrium in the domestic gas market will continue for the foreseeable future. In this circumstance, providing market signals such as an indicative price to market participants (especially new entrants and gas users) becomes more important.

The process for calculating the indicative price based on actual invoices would need to include the collection of data about the key commercial features of each producer GSA as well as invoice data. There may be a need to confer a statutory power to obtain this information, and to govern the disclosure of the information. The relevant details of each GSA would include: contract date, contract duration, name of buyer and location of gas use, take or pay percentage, load factor (or the data used to calculate load factor), supply basin, and the contract price/price review mechanism.

There would also have to be an assessment of the age or relevance of the contract to the current market. The prices and key terms and conditions in legacy contracts may skew the calculation of a current indicative price, at least where a price review has not been undertaken in the past several years.

The Inquiry considers that, at present, a feasible model for an indicative price would be to publish an east coast volume-weighted average price, or a separate price for gas produced in each of Victoria and Queensland⁹⁵, for:

- agreements for the supply of gas by producers, which have a take or pay percentage of 80–85 per cent and a load factor of 110–130 per cent
- agreements for the supply of gas by producers, which have a take or pay percentage of 90–95 per cent and a load factor of 110–130 per cent.

There may also be merit in publishing an average take or pay multiplier (weighted by volume), and an average load factor (weighted by volume) for each published volume-weighted average price, as this may be of additional assistance to buyers in evaluating particular offers against those indicative prices.

At present, there are around 15 GSAs in each of these categories that have a duration of three months or more. While some of these agreements pre-date the changes in market conditions that have occurred in the last few years, it is likely that most of them have been the subject of price reviews within that period. In any event, some of the older agreements will expire within the next 12–18 months.

The Inquiry considers that there are likely to be a sufficient number of gas supply agreements to enable the calculation of these indicative prices for Queensland, and for an indicative price for a take or pay percentage of 80–85 per cent and load factor of 110–130 per cent for Victoria, without giving rise to confidentiality concerns, although this is an issue that may require further evaluation by AEMO or by the AER.

AEMO or the AER would need to be able to revise the take or pay and load factor parameters outlined above in response to changing market conditions, so that the outputs of the indicative price series continue to be a meaningful reflection of key observed market outcomes. There would also be merit in ensuring that publication of the invoice-based indicative price is

⁹⁵ Gas produced at Moomba could be included in either of these calculations, depending on the actual or likely destination for that gas.

accompanied by qualitative commentary on changes in the market over time to provide additional guidance to market participants.

For example, if most GSAs move to a 90 per cent or more take or pay percentage over time, or if there are any older prices that are having a significant impact on a particular indicative price, this would be useful information for the market. Qualitative commentary would also be the appropriate way of outlining and commenting on the range of actual prices that have contributed to the weighted average, without disclosing those prices themselves. It would also assist in addressing some of the fundamental issues around asymmetrical information in the market that have led to this Inquiry.

5.2.4 Limitations and costs of publishing an invoice-based indicative price series

While there are considerable potential benefits in AEMO or the AER publishing an indicative price based on actual invoices and the most important commercial terms (take or pay percentage and load factor), there are some relevant factors that might limit the extent of those benefits. There would also be some costs associated with this work. As such, before a decision to proceed with an indicative price is finalised, it would be appropriate for the AEMC to consult further with gas buyers about whether the model outlined above will deliver sufficient benefits, including in light of the publication of the Wallumbilla LNG netback price as discussed above, to make publishing an indicative price based on actual invoices worthwhile:

- There is a risk that in publishing quantitative information, particularly on a basin-by-basin basis, it would increase the potential for tacit price collusion or price signalling by producers. This may in turn increase the compliance costs for regulators who may have to monitor any signs of such behaviour closely.
- There is a risk that producers might seek to influence the outputs of the indicative price series by changing their pricing offers to buyers. However, these risks can be mitigated by including all relevant GSAs in the calculation of the price series rather than relying on a sample, and by basing the price series on actual invoices rather than on the offers that are being made at any one point in time. The Inquiry also notes that, at present, there is scope for producers to influence market expectations via the selective release of pricing or other commercial information.
- There would be an initial set-up cost for the systems and personnel undertaking the work and an ongoing cost to market participants in supplying the data and information necessary to compile an indicative price. It would be expected that many aspects of the process would not need to be repeated, or could be repeated very efficiently, after the initial set-up.
- In considering benefits and costs, a decision will also have to be made on the regularity of reporting an indicative price. Given the limited number of contracts being negotiated at any one time, it would seem likely that publishing a price every six months would provide a sufficient price indicator for most market participants. However, AEMO or the AER should also be able to decide on the timeframes for its release given the access that they would have to the relevant contract and invoice information.

6 Pipelines are responding to market changes but there is evidence of monopoly pricing

While gas supply is crucial for the market, the efficiency of the gas market is also critically dependent on the efficiency of the transmission sector, the prices pipeline operators charge for transportation services and the ability of this sector to respond to change.

The material gathered through the Inquiry indicates that most transmission⁹⁶ pipeline operators have responded in a dynamic way to the changes currently underway in the market. In the main, pipeline operators have undertaken necessary investments in a timely manner and offered more flexible services to meet the changing needs of some users and producers.

Concerns have nevertheless been raised by a number of market participants about the market power wielded by some pipeline operators, the ways in which this market power is being exercised, and the detrimental effect it is having on economic efficiency and consumers more generally.

The Inquiry has investigated these concerns and found that the majority of existing transmission pipelines on the east coast have market power and face limited constraints when negotiating with shippers. There is also evidence that a large number of the major arterial pipelines on the east coast and pipelines servicing regional areas are using their market power to engage in monopoly pricing, which is not surprising.

The term monopoly pricing is defined in this context as prices that significantly exceed the long-run average cost of supply for a sustained period, or more simply prices in excess of what would prevail in a workably competitive market.⁹⁷ It is important to note that monopoly pricing does not amount to a contravention of the CCA. Further, it is legitimate and expected commercial behaviour. In a market economy where the profit motive drives private enterprise, it is expected that firms that do not face effective competition, or the threat of such competition, will engage in monopoly pricing. Monopoly pricing can, nevertheless, operate to the detriment of consumers because it gives rise to higher consumer prices, distorts market outcomes and adversely affects the economic efficiency of markets.

Anecdotal and other evidence gathered through this Inquiry indicates that monopoly pricing by transmission pipelines is giving rise to higher delivered gas prices for users and in some cases lower ex-plant prices for producers. This is, in turn, having an adverse effect on the economic efficiency of the east coast gas market and upstream and downstream markets, with some of the more significant economic inefficiencies likely to flow from this behaviour including:

- lower than efficient levels of gas production and investment in exploration and reserves development, at a time when the market requires new sources of supply to be brought online and greater diversity of supply
- lower than efficient levels of gas use and investment in facilities that use gas
- inefficient pipeline utilisation, distortions in gas flows across the market, and gas failing to flow to where it is valued most highly.

These inefficiencies can be expected to result in consumers facing higher domestic gas prices and higher prices for products and services produced using gas.

⁹⁶ The Inquiry only focused on transmission pipelines not distribution pipelines. References in this chapter and the following chapters to pipeline operators should therefore be interpreted as references to the operators of transmission pipelines.

⁹⁷ This definition is consistent with the following definition adopted by the Independent Committee of Inquiry on National Competition Policy (the Hilmer Committee):
"In markets characterised by workable competition, charging prices above long-run average full costs will not be possible over a sustained period, as above-commercial returns will attract new market participants or lead consumers to choose a rival supplier or substitute product. Where the conditions for effective competition are absent—such as where firms have a legislated or natural monopoly or the market is otherwise poorly contestable—firms may be able to charge prices above efficient levels for periods beyond a time when a competitive response might reasonably be expected. Such 'monopoly pricing' is detrimental to consumers and to the community as a whole."
Report by the Independent Committee of Inquiry on National Competition Policy, Final Report, 1993, p. xxxiii.

Many would expect the gas access regime (as set out in the National Gas Law (NGL) and National Gas Rules (NGR)) to be capable of addressing this market failure (that is, monopoly pricing that gives rise to economic inefficiencies). However, the Inquiry has found the regime is not posing an effective constraint on the behaviour of the majority of existing pipelines. The reasons for this are explored in further detail in chapter 7, along with the Inquiry's recommendations on how the gas access regime could be strengthened.

6.1 Most pipeline operators are responding to the changing market

The gas transmission pipeline network on the east coast has undergone a major transformation over the last 15 years, with a large number of new pipelines being constructed, including most recently the three pipelines servicing the LNG facilities in Gladstone.⁹⁸ A number of significant incremental investments to existing pipelines and facilities have also occurred over this period. The more recent examples include:

- the expansion of the Eastern Gas Pipeline (EGP), the Queensland Gas Pipeline (QGP), the export capacity of the Declared Transmission System (DTS), and the Moomba to Sydney Pipeline (MSP)
- the connection of the EGP to the MSP and the SEA Gas Pipeline to the Moomba to Adelaide Pipeline System (MAPS)
- the augmentation of compression facilities at Wallumbilla and Moomba
- the conversion of the MSP, the MAPS, the South West Queensland Pipeline (SWQP), the Queensland to South Australia/New South Wales Link (QSN), the Roma to Brisbane Pipeline (RBP) and the Berwyndale to Wallumbilla Pipeline (BWP), into bi-directional pipelines.

In total, these recent investments are estimated to have cost \$900 million, with over 50 per cent of that investment occurring to enable more gas from Victoria to flow north into New South Wales and up to Queensland. Of the projects listed, the expansion of the export capacity of the DTS has involved the most significant investment, with \$260 million reportedly being spent to expand the export capacity for various shippers over the last 3.5 years.⁹⁹

The Northern Territory Government's decision in late 2015 to award Jemena the right to construct and operate the NGP is expected to result in further investment in the next two to three years¹⁰⁰, with Jemena stating that it expects the pipeline to be completed in 2018.¹⁰¹ Jemena has also noted the potential to build another pipeline connecting Mt Isa and Wallumbilla if sufficient gas from the Northern Territory is available.¹⁰²

These investments have facilitated the development of a more interconnected network on the east coast, as highlighted in figure 6.1, and are paving the way for more flexible and dynamic services to meet the changing needs of some participants, as outlined in box 6.1.

98 Some other pipelines developed in this period include the EGP, TGP, SEA Gas, QSN, the BWP and a number of other smaller pipelines in Queensland.

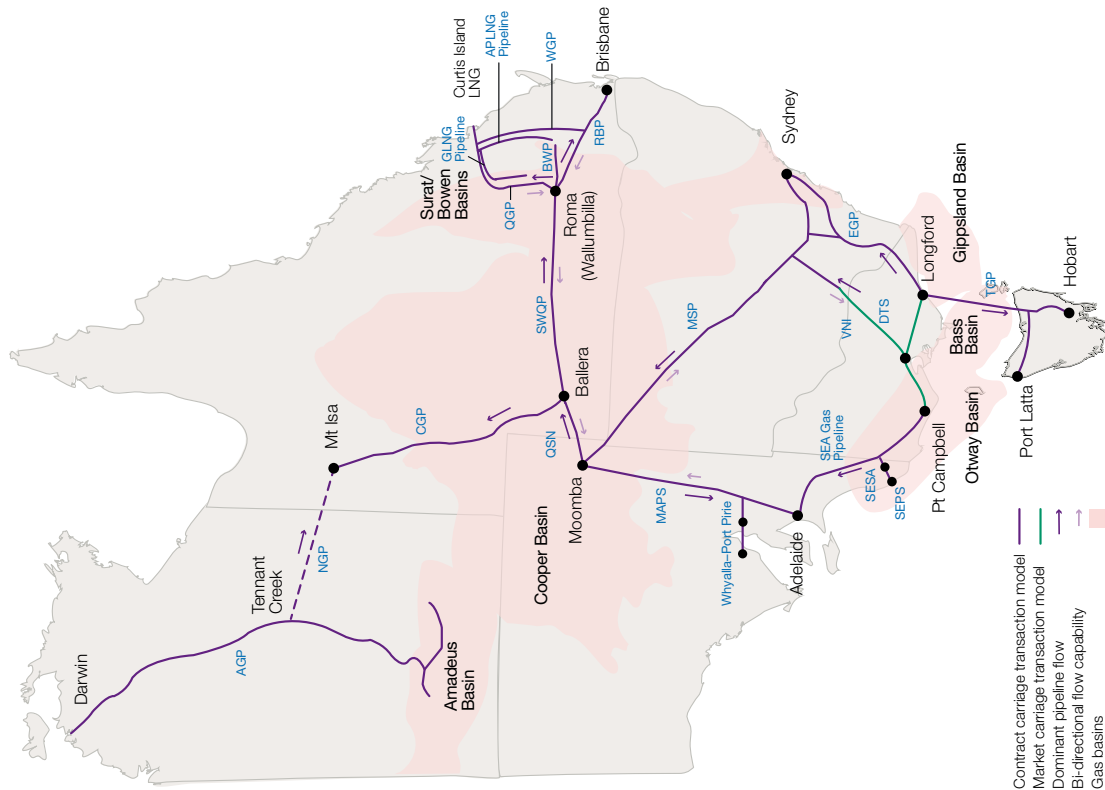
99 APA, *Financial Report, 2013, Financial Report, 2014, Financial Report, 2015 and Interim Financial Report 2016*.

100 Chief Minister of the Northern Territory, 'NT Announces Jemena to build gas pipeline to east coast', 17 November 2015.

101 Jemena, media release, 'Jemena to build North East Gas Interconnector', 17 November 2015.

102 *ibid.*

Figure 6.1: Transmission pipelines on the east coast¹⁰³



State	Pipeline	Owner	Regulatory status
NSW	Moomba to Sydney Pipeline (MSP)	APA	Unregulated: Mooba to Marsden/ Light regulation: Remainder
	Eastern Gas Pipeline (EGP)	Jemena	Unregulated
	Central Ranges Pipeline (CRP)	APA	Full regulation
SA	Central West Pipeline (CWP)	APA	Light regulation
	Moomba to Adelaide Pipeline System (MAPS)	Epic	Unregulated
	SESA Pipeline (SESA)	APA	Unregulated
	South East Pipeline Systems (SEPS)	Epic	Unregulated
	Whyalla-Port Pirie	Epic	Unregulated
	SEA Gas Pipeline	Rest/APA	Unregulated
	Riverland Pipeline	AGN	Unregulated
	Declared Transmission System (DTS)	APA	Full regulation
	Vic-NSW Interconnect (VNI)	APA	Unregulated
	Carisbrook to Horsham Pipeline (CHP)	Gas Pipelines Victoria	Unregulated
Qld	South Gippsland Pipeline (SGP)	Multinet	Unregulated
	Roma to Brisbane Pipeline (RBP)	APA	Full regulation
	South West Qld pipeline (SWQP)	APA	Unregulated
	QSN Link (QSN)	APA	Unregulated
	Queensland Gas Pipeline (QGP)	Jemena	Unregulated
	Carpentaria Gas Pipeline (CGP)	APA	Light regulation
	Berwyndale to Wallumbilla Pipeline (BWP)	APA	Unregulated
	Wallumbilla to Darling Downs Pipeline (DDP)	Origin	Unregulated
	Cheepie to Barcaldine Pipeline (CBP)	Ergon	Unregulated
	Dawson Valley Pipeline (DVP)	Meridian/Westside JV	Unregulated
	North Old Gas Pipeline (NOGP)	Vic Funds Management Corp.	Unregulated
	Wallumbilla to Gladstone Pipeline (WGP)	APA	15-year no-coverage
	APLNG Pipeline	Origin/Conoco/Sinopec	15-year no-coverage
Tas	GLNG Pipeline	Santos/Petronas/Total/Kogas	15-year no-coverage
	Comet Ridge to Wallumbilla Pipeline Loop	Santos/Petronas/Total/Kogas	15-year no-coverage
NT	Tasmanian Gas Pipeline (TGP)	Palisades	Unregulated
	Amadeus Gas Pipeline (AGP)	APA	Unregulated
	Northern Gas Pipeline (NGP) (proposed)	Jemena	n/a

103 Appendix 4 contains further detail on the regulatory status of pipelines and how this has changed over time.

Box 6.1: Changing demand for pipeline services

The changes underway in the east coast gas market and in downstream markets in which gas users compete (for example, electricity generation) are affecting the nature of the demand for transportation and storage services and the degree of flexibility being sought by shippers in their GTAs. For example:

- Many GPGs are reducing their output from historical levels in response to changed conditions in the National Electricity Market. This has prompted a number of these generators to look for more flexible and cost-effective gas transportation services that enable them to operate in peak periods but don't require the payment of a fixed cost throughout the year. Some pipelines have responded to this need by introducing a peaking service, which is only payable when generators use the service.
- LNG projects have to be able to respond relatively quickly to unexpected outages of their LNG plants and/or production facilities. This has prompted some LNG projects to look to pipeline operators for more flexible transportation and storage services across multiple pipelines (for example, 'as available' or interruptible services, which only have to be paid for when the services are used but may be subject to a minimum bill) and to access the bi-directional capability of some pipelines.
- Larger retailers are looking to move gas to where it is valued most (for example, to residential customers, industrial users, GPGs or LNG export projects) and to take advantage of arbitrage opportunities that emerge across the facilitated markets. In a similar manner to LNG projects, this has prompted some retailers to look for greater flexibility in their GTAs to move gas across multiple pipeline routes.

Another factor that is influencing this change is the decision by some producers to move to shorter-term GSAs and to provide buyers less flexibility to manage demand variations (see chapter 4). This has led some shippers to look to pipeline storage (park and park and loan) services to manage their daily demand, and to shorter-term gas transportation agreements.

Evidence received through the Inquiry indicates that pipeline operators have responded relatively well to the changing demands by offering more innovative services (for example, bi-directional services, peaking transportation services, interruptible services and premium storage services), shorter-term GTAs and multiple services across inter-connected pipelines (for example, storage, compression, redirection and transportation services).

With the exception of one or two of the smaller incremental investments noted above, the investments have been underwritten by shippers through medium to long-term GTAs. The demand related risks faced by pipeline operators in carrying out these investments have therefore been relatively low, which is indicative of the desire that pipeline operators have not to be exposed to demand related risks. This desire can largely be attributed to the constraints imposed by financiers, who understandably want greater surety of demand given the high upfront costs associated with these investments and the fact that they have few alternative uses if demand does not eventuate.

The effect of these constraints on pipeline investment can be seen in the following statements that were made by one pipeline operator during its hearing:

"We all have financing, so, you know, if you want good debt terms, you can't have a lot of uncontracted capacity, otherwise your risk profile will change."

"...we don't speculatively build capacity. Our business model would suggest that's too risky, and we can't offer the same low cost of capital to build these types of projects."

These financial constraints also explain why new pipelines only tend to be built to meet the foundation shippers' demand and why existing pipelines tend to be expanded in stages to meet incremental increases in demand. While it has been previously suggested by pipeline operators that pipelines are built or expanded in this manner because of the risk of regulation, there was no indication of this in the material pipeline operators provided to the Inquiry. The only rationale that

was cited in this material was the capital constraint imposed by financiers, which is not unique to gas pipelines or to infrastructure that faces the threat of regulation.¹⁰⁴

Some other interesting points that are worth noting from figure 6.1 are that:

- Of the 30 or so transmission pipelines on the east coast APA has an interest in 13 (the SWQP, QSN, BWP, RBP, MSP, DTS, Carpentaria Gas Pipeline (CGP), Wallumbilla to Gladstone Pipeline (WGP), Central Ranges Pipeline (CRP), Central West Pipeline (CWP), the Vic-NSW Interconnect (VNI), SESA Pipeline and SEA Gas Pipeline)¹⁰⁵, Jemena has an interest in two (the EGP and QGP) and Epic has an interest in two (MAPS and South East Pipeline System (SEPS)).
- There are currently only 5.5 pipelines that are subject to regulation, three of which are subject to full regulation (the DTS, RBP and CRP) and 2.5 to light regulation (the CWP, CGP and MSP south of Marsden). The MSP is unregulated between Moomba and Marsden. Four pipelines have also currently been granted a 15-year no-coverage determination (the WGP, APLNG Pipeline, GLNG Pipeline and Comet Ridge to Wallumbilla Pipeline Loop (CRWPL)).

Further detail on the regulatory regime that applies to transmission pipelines can be found in chapter 7.

6.2 There are few constraints on the behaviour of existing pipelines

Transmission pipelines tend to have cost structures that approximate those of a natural monopoly. They are highly capital intensive to construct and involve significant sunk costs in assets with limited alternative uses. Pipeline costs per unit decrease as the size of the pipeline diameter increases. Adding compression to enhance the capacity of an existing pipeline is often much cheaper than building a new pipeline to meet any need for increased capacity.¹⁰⁶ While capital costs are high, operating costs tend to be relatively low. This gives a cost profile where average costs tend to decrease as transportation volumes increase over a wide range of output. As a result of these characteristics it can be more efficient for one pipeline to supply a market, rather than two or more pipelines. Further, these natural monopoly characteristics can create a high barrier to entry for prospective competitors to an existing pipeline, which in turn tends to enhance the market power of existing gas pipelines.

Market power comes from the lack of competitive constraint. A pipeline operator with market power is able to act without significant constraint from competitors, potential competitors or customers. For the purposes of assessing the market power of transmission pipelines on the east coast, the Inquiry considered the potential constraints affecting new and existing pipelines when negotiating with shippers and prospective shippers. A distinction has been drawn in this context between the market power of new and existing pipelines, because they differ in a number of important respects, as outlined below.

6.2.1 Competition to build a new pipeline can be effective in limiting market power

If there is effective competition to develop and build a pipeline ('competition for the market'), then the market power of the ultimate pipeline owner is likely to be limited for a period of time. By negotiating prior to the pipeline being built, foundation shippers will usually be able to use competitive tension between prospective pipeline owners to negotiate long-term contracts that are not affected by the exercise of market power.

¹⁰⁴ This type of capital constraint applies to a range of other large scale investments where there is some degree of demand risk. For example, banks usually require commercial real estate developers to demonstrate a relatively high pre-commitment by tenants before they will lend to the developer.

¹⁰⁵ APA has a 50 per cent interest in the SEA Gas Pipeline.

¹⁰⁶ There are limits to this, depending on the original design specification of the pipeline. Still, these features hold over a wide range of pipeline capacities.

Competition to develop and build pipelines has occurred in a small number of cases in the last 10 years. For example:

- In 2014, a number of parties submitted expressions of interest to the Northern Territory Government to build the NGP. Four bidders (APA, Jemena, DUET and Pipeline Consortia Partners Australia) were selected from these expressions of interest to compete via a request for proposal process. Under the proposal process, bidders were free to compete by offering different combinations of construction timing, capacity, pricing, routes and other terms and conditions. The rate of return adopted in the winning bid suggests that there was a reasonable level of competition between these bidders.

Through this process, the Northern Territory Government also used the competitive tension between prospective pipeline operators to include access provisions relating to the supply of pipeline services by the successful bidder to third parties that may wish to become shippers on the NGP in the future in the final project development agreement. By following the process set out in the agreement, future shippers can become contractual parties to a transportation agreement based upon the access provisions.

- In 2007, Epic and APA competed to develop a new pipeline to enable gas from Queensland to be transported into the southern states. Epic proposed reversing the flow and expanding the capacity of the SWQP and constructing the QSN, while APA proposed the construction of a new pipeline from Wallumbilla to Bulla Park.¹⁰⁷ Epic ultimately won this contest, with AGL and Origin entering into foundation contracts in 2007 and 2009, respectively.¹⁰⁸ The prices and other terms and conditions in these foundation contracts suggest that AGL and Origin both benefited from this competition. Ownership of the SWQP and QSN was later transferred to APA when it acquired the Hastings Diversified Utilities Fund in 2012.

The outcomes of these two competitive processes suggest that ‘competition for the market’ can impose an effective constraint on the behaviour of new pipelines. It is important to recognise, however, that the effect of this competitive constraint will dissipate once the new pipeline has been developed, which is why foundation shippers tend to use competitive tension between prospective pipeline operators to negotiate long-term GTAs that protect their investments over the term of the GTA.

6.2.2 There are limited constraints on the behaviour of the majority of existing pipelines

While some long-term contracts are negotiated prior to a pipeline being developed and built, it is more often the case that shippers must negotiate with the owner of an existing pipeline, because:

- a foundation shipper’s contract comes to an end
- a foundation shipper requires a variation of its GTA or requires transportation services in addition to those anticipated at the time the foundation contract was negotiated
- a new shipper is party to the development of a gas field or is investing in a plant in close proximity to an existing pipeline.

The ability and/or incentive of an operator of an existing pipeline to exercise market power in these circumstances may potentially be constrained by a range of factors, including:

- competition from other pipelines (existing or new pipelines)
- competition from alternative energy sources
- the risk of asset stranding (full or partial)
- the countervailing power of shippers
- regulation or the threat of regulation.

¹⁰⁷ At the time this competition occurred, Epic was owned by Hastings Diversified Utilities Fund.

¹⁰⁸ AGL media release, ‘AGL secures pipeline deal to link its gas to eastern markets’, 13 July 2007 and Origin media release, ‘Origin completes gas transportation agreement with Epic’, 15 December 2009.

Drawing on internal documents provided by pipeline operators and other material gathered through the Inquiry, the Inquiry has examined the extent to which these factors are constraining the behaviour of existing pipelines. The findings are outlined below.

Competition from other pipelines

A pipeline can potentially face two types of competition from other gas pipelines:

- direct competition, which involves two or more independently owned pipelines transporting gas from the same gas field to the same destination, or
- indirect competition, which involves two or more independently owned pipelines competing to supply gas from different fields to the same destination.

On the east coast, indirect competition is more common than direct competition although there are some notable examples of pipelines that service the same production and demand areas, including:

- the EGP and the MSP via the DTS, both of which provide for the supply of gas from Longford to Sydney and Canberra
- the three LNG pipelines (APLNG Pipeline, GLNG Pipeline and the WGP), which enable gas to be supplied from the Bowen/Surat basins to the LNG projects in Gladstone.

Historically, competition between pipelines has only occurred in Sydney, Canberra and Adelaide, with all other locations on the east coast (excluding Gladstone) serviced by a single pipeline. The change in the pattern of gas flows across the east coast is, however, giving rise to some significant changes in the competitive dynamics between pipelines.

For example, the expected reduction in the volume of gas flowing from Moomba to the southern states means that:

- the MAPS may be a less effective constraint on the SEA Gas Pipeline for supply into Adelaide than it was in the past
- the MSP via Moomba may be a less effective constraint on the EGP for supply into Sydney and Canberra than it was in the past.

This point was acknowledged in the internal documents provided by a number of the pipeline operators and during the hearings as highlighted in the following quotes from two pipeline operators:

“We don’t actually see [...] as competitive or as a competitor. The reality is it’s an integrated supply chain now in terms of the market. So in terms of where [...] and what will happen in the future it’s about which markets require gas to them and how do you get gas to them... So it may well be customers requiring flexibility to be able to take gas down our pipeline, [...] going in the other direction.... Or alternatively gas coming into [...] from Longford which may well be displaced in some markets via the Narrabri type gas, and the Longford gas making its way across into [...] and then possibly up us somewhere else. So we tend not to see [...] as a competitor.”

“Pricing of transportation from Moomba is less than [...] reference tariff, however, Moomba’s limited available gas supply reduces the likelihood of this being a credible alternative in this period.”

The increase in the volume of gas flowing north from Victoria is also resulting in changes in the competitive dynamics with competition emerging between:

- the EGP and MSP via the DTS for deliveries to Sydney and Canberra
- the western (SEA Gas/MAPS), central (DTS/MSP) and eastern (EGP/MSP) routes for deliveries to Moomba.

While competition is emerging on these new routes, there is evidence that some pipeline operators are still exercising market power along these routes (see section 6.3), which implies that competition between the various pipelines is not as effective as might be expected. On some of these new routes, pipelines that have traditionally competed with each other for supply

into Adelaide, Sydney and the ACT (for example, MAPS and SEA Gas Pipeline, and the MSP and EGP) are starting to operate as complements, rather than substitutes, under some transactions.

If the NGP is built, then the competitive dynamics may change further depending on whether gas is supplied south from Mt Isa. If the NGP is only used to supply gas to Mt Isa, then it will compete with the CGP for supply to this location. If, however, it is used to supply gas into the remainder of the east coast, then the NGP and CGP will become complements and compete with the QSN for supplies into Queensland from Moomba, or the SWQP for supplies into the southern states from Wallumbilla. How much it will compete is, however, unclear given APA owns the CGP, SWQP and QSN.

Setting these examples aside, there are, as highlighted in figure 6.1, a large number of pipelines on the east coast that are not subject to any form of competition from other pipelines, including:

- major arterial pipelines, such as the SWQP, QSN, RBP, DTS and the Tasmanian Gas Pipeline (TGP)
- smaller pipelines, including those servicing regional areas, such as the BWP, CGP, CRP, CWP, SEPS, SESA Pipeline, South Gippsland Pipeline (SGP), Riverland Pipeline, Cheepie to Barcaldine Pipeline (CBP), Dawson Valley Pipeline (DVP), Wallumbilla to Darling Downs Pipeline (WDP), North Queensland Gas Pipeline (NQQP) and laterals on some major arterial pipelines (for example, the Whyalla and Angaston laterals on the MAPS and the Griffith, Lithgow and Wagga laterals on the MSP).

Competition from alternative energy sources

Competition from alternative energy sources (for example, electricity) is often cited as a constraint on the behaviour of pipeline operators, but the material gathered through the Inquiry suggests that at best competition from other energy sources provides a weak constraint on transmission pipelines.

That is, while there have been instances in the past where competition for the market from alternative energy sources has constrained the price that transmission pipelines charge during the period of competition¹⁰⁹, there was no evidence in the internal documents provided by pipeline operators that competition from other energy sources is currently posing much constraint, or has done so in the last two to three years.

Risk of asset stranding (full or partial)

In a market characterised by sunk and largely fixed costs, the risk of full or partial asset stranding may impose a constraint on the incentive a pipeline operator otherwise has to exercise market power.

While there is some evidence that the decline in GPG on the east coast and changes in the pattern of gas flows across the east coast are exposing some pipelines to partial asset stranding risk, the pipelines that are facing this risk have not reduced their prices to attract more demand to counter this risk. To the contrary, some have actually increased their prices, with one pipeline raising prices by over 90 per cent even in the face of declining volumes. The risk of asset stranding does not therefore appear to be providing an effective constraint on the behaviour of those pipelines facing this risk.

Countervailing power of shippers

Countervailing power arises when buyers have special characteristics (for example, size or commercial significance) that enable them to credibly threaten to bypass the pipeline (for example, by building their own pipeline or sponsoring new entry). While there have been examples in the last 10 years of larger shippers developing pipelines to bypass existing pipelines

¹⁰⁹ One of the more notable examples of this form of competition occurred in Mt Isa in 2011 through a competitive tender process that considered two alternatives:

- the development of localised generation in the Mt Isa region
- the development of an electricity transmission line that would connect North West Queensland to the National Electricity Market.

A joint bid by APA and AGL to develop the Diamantina GPG plant in Mt Isa was the ultimate winner of this process.

or credibly threatening to use an alternative energy source, there was no evidence in the material provided by pipelines that countervailing power has placed a constraint on the prices negotiated in the last two to three years, or the prices currently being offered.

The risk of bypass, more generally, appears to be having little effect on the prices currently being proposed by some pipelines, as highlighted in the following statement in one pipeline operator's Board Paper¹¹⁰:

"The proposed [...] tariff [...] has been canvassed with potential shippers. This tariff is higher than the effective tariff for a 'new build' bypass pipeline and higher than the current [...] backhaul tariff."

Regulation or the threat of regulation

In the mid-1990s state and territory governments agreed to implement an industry specific access regime for gas transmission and distribution pipelines. The gas access regime came into effect in late 1997. With the exception of one or two smaller transmission pipelines, all the transmission pipelines on the east coast were deemed to be regulated when the regime came into effect.

In the intervening period regulation has been revoked on a number of key pipelines and a large number of new pipelines that have been developed have not become subject to regulation. There are now just 5.5 pipelines that are subject to some form of regulation under the NGL and NGR, which amounts to less than 20 per cent of the transmission pipelines on the east coast (see appendix 4 for more detail on the regulatory status of pipelines and how this has changed over time).

The relatively small number of pipelines that are subject to regulation is in direct contrast to what occurs in other comparable jurisdictions, such as the US, the European Union (EU) and New Zealand, where the vast majority of transmission pipelines are regulated. The market power wielded by existing pipelines is well recognised in these jurisdictions even in cases where producers and users have a number of transportation options to supply or source gas, as noted by the Brattle Group in a report to the NCC¹¹¹:

"Most supply basins in North America and Europe have more than one pipeline accessing them. Many destination markets have multiple pipelines serving them. Despite the greater 'thickness' of these markets, pipelines in these jurisdictions are still considered to have natural monopoly characteristics and are regulated with respect to price and terms and conditions of service."

While many would expect that regulation, or in some cases the threat of regulation, would constrain the behaviour of pipelines, internal documents provided by the pipeline operators revealed that the gas access regime, in its current form, is not posing an effective constraint on the behaviour of:

- Unregulated pipelines—There was no evidence in the material provided by pipeline operators that the threat of regulation was posing a constraint on the behaviour of any of the unregulated pipelines. The prices paid for some pipelines in sales processes carried out over the last five years also suggest that purchasers are assuming little reduction in returns from the potential for future regulation. So too does the internal analysis carried out by one pipeline operator, which indicated that it is earning 70 per cent more revenue than it would if it was subject to full regulation.
- Regulated pipelines—There is evidence that some pipelines that are subject to full regulation are taking advantage of the limitations in the gas access regime to exercise market power (see chapter 7 for more detail on these limitations). The Inquiry was also presented with evidence that at least two pipelines subject to light regulation are exercising market power.

¹¹⁰ The pipeline operator's ability to offer tariffs in excess of the bypass cost stems from the fact that the individual loads of most of the shippers on this pipeline would not have been sufficient to underpin the development of a 'new build' bypass pipeline. On the pipeline in question, the co-ordination of shippers is unlikely.

¹¹¹ Brattle, *Competition in Gas Pipeline Markets: International Precedent for Regulatory Coverage Decisions*, June 2000, p. 4.

The threat of arbitration under the NGL in these cases appears to be having little influence on the behaviour of these pipelines, with some shippers informing the Inquiry that the costs and resources associated with an access dispute, coupled with the uncertainty surrounding how the AER would approach certain issues¹¹² and the final outcome¹¹³, discourage shippers from triggering these provisions. Information asymmetries may also be contributing to this reluctance to trigger these provisions because shippers are unable to determine how much they are being 'overcharged' (see chapter 7 for more detail).

A number of shippers also noted the lack of constraint posed by the existing regime, with some pointing to the decision not to regulate ('cover') the SEPS in 2013 as evidence of the regime's inability to constrain the behaviour of pipeline operators even when the pipeline in question is a monopoly. One shipper also informed the Inquiry that it had obtained advice that another major arterial pipeline that is not subject to any form of competition and had raised prices by 90 per cent was unlikely to satisfy the test for regulation (the coverage criteria). Material provided by the pipeline operator in question indicated that it had also obtained expert advice on this issue, which concluded it was unlikely to satisfy the test for regulation because access was unlikely to result in a material increase in competition in another market.

Given the experience shippers have had in this area, it is not surprising that the threat of regulation under the NGL and NGR is not posing an effective constraint on the behaviour of pipeline operators, or that shippers have been reluctant to apply to have other major bottleneck pipelines, such as the SWQP/QSN, regulated. The National Competition Council's (NCC) recent observation in the Port of Newcastle case that 'excessive' or 'monopolistic' pricing is not the focus of Part IIIA¹¹⁴, can be expected to add to the reluctance shippers have to applying to have pipelines regulated under the current test for regulation in the NGL and NGR, which largely mirrors the test under Part IIIA. This issue is discussed in further detail in chapter 7.

Conclusions on constraints faced by existing pipelines

The preceding discussion suggests that the majority of *existing* transmission pipelines on the east coast have market power and their ability and incentive to exercise that power is not being effectively constrained at this time. Even where competition is present, it is clear from the material gathered through the Inquiry that competition is not posing as effective a constraint as might be expected. A similar observation can be made about the gas access regime, which is also failing to impose an effective constraint on pipeline operators, either directly through regulation or indirectly through the threat of regulation. This issue is discussed in further detail in chapter 7.

6.3 Pipelines with market power are using that power, and this is to be expected

During the Inquiry, concerns were raised by a large number of market participants about the ways in which existing pipeline operators are exercising their market power, with specific concerns raised about:

- the prices charged for some services being higher than would be expected in a workably competitive market, or under regulation
- the potential for a greater degree of bundling and reduced transparency of transportation costs across particular routes in the future
- the costs being levied for incremental modifications to pipelines (including the costs of front end engineering and design studies).

¹¹² For example, there was some uncertainty as to how the AER would value pipelines that have been in operation for a period of time, and how it would deal with other issues, such as excess capacity and redundant assets.

¹¹³ The Inquiry is aware that concerns were also raised about the access dispute provisions to the Victorian Gas Market Taskforce that was chaired by former Federal Minister Peter Reith and that the Taskforce recommended that further work be done to ensure that the access dispute framework is operating effectively. Gas Market Taskforce, *Final Report and Recommendations*, October 2013, p. 42.

¹¹⁴ NCC, *Final Recommendation: Declaration of the shipping channel service at the Port of Newcastle*, 2 November 2015, p. 13.

Concerns have also been raised in the AEMC's East Coast Gas Market Review about the potential for pipeline operators to engage in inefficient price discrimination.

The Inquiry has examined these concerns as part of a broader investigation into whether any pipeline operators are exercising market power by:

- engaging in monopoly pricing
- engaging in anti-competitive bundling or tying (for example, foreclosing competition by charging a lower price for the bundled service than the price of individual services, or by making the sale of one service conditional on the purchase of another)
- restricting or denying access to the services provided by the pipelines
- engaging in anti-competitive price discrimination (for example, by pricing in a manner that favours affiliates, raises barriers to entry or amounts to predatory pricing)
- reducing the quality of services provided by the pipelines.

A summary of the Inquiry's findings is provided in table 6.1.

Table 6.1: Summary of Findings on Exercise of Market Power

Form of market power	Evidence of behaviour?	Findings
Monopoly pricing	Yes	A large number of small and large pipelines servicing supply centres, capital cities and regional areas on the east coast are pricing above levels one would expect in a workably competitive market.
Anti-competitive bundling or tying	No but possibility of bundling in the future	<p>Bundling: There is no evidence that any pipeline operators are currently bundling the price of transport across two or more pipelines. There are, however, indications that it may become more prevalent in the future, which could, depending on the form it takes, adversely affect competition.</p> <p>Tying: There is no evidence that pipelines are making the purchase of one service conditional on the purchase of another service, or making access to a pipeline conditional on the use of another pipeline.</p>
Restricted access or denial of access	No	Access to the services provided by pipelines has not been a significant issue. This is not surprising given the majority of pipelines are vertically separated and operating on an open access basis and therefore have no incentive to discourage access.
Anti-competitive price discrimination	No	<p>There is no clear evidence that pipelines are engaging in anti-competitive price discrimination. That is not to say all shippers are paying the same price. The differences can, however, in most cases be explained by:</p> <ul style="list-style-type: none"> • differences in the services obtained by shippers under their GTAs • differences in the contract term, with discounts sometimes offered for long-term GTAs (or premiums payable for short-term contracts) • investments that are required to provide the service (for example, expansions). <p>The differences in some cases also reflect the availability of other options to the shippers, with the prices charged to shippers that can utilise an alternative pipeline being lower in some cases than the prices charged to 'captured' shippers that have no other alternative.</p>
Reductions in service quality	Rare	<p>There is limited evidence of pipeline operators trying to reduce service quality, with the only instances cited in the Inquiry including:</p> <ul style="list-style-type: none"> • one pipeline operator that has ceased to offer services that allow shippers to minimise the cost of managing variations in demand (for example, as available and overrun services, delivery point changes) in an attempt to force shippers to contract more firm capacity • another pipeline operator that has taken a long period of time to facilitate changes in delivery points and tried to limit the number of times delivery points can be changed, which has the potential to affect secondary capacity trading.

As table 6.1 highlights, there is evidence that a number of major pipelines are engaging in monopoly pricing and that bundling of services and prices across pipelines may become more prevalent in the future. There is, however, no evidence that pipeline operators are engaging in anti-competitive price discrimination. Exercise of the other forms of market power is also either rare or non-existent.

Further detail on monopoly pricing is provided below. In relation to bundling, depending on the form it takes, this type of behaviour can either benefit end-users (that is, through lower prices) or foreclose competition (that is, by deterring customers from using other competing pipelines). While some concerns were raised about foreclosure, the Inquiry has not seen any evidence of this behaviour to date. That is not to say it could not occur in the future on those routes where there is some competition to supply.¹¹⁵ However, if it was to occur then, depending on the form the bundling takes, recourse might be had to the misuse of market power provisions in s. 46 of the CCA and/or the exclusive dealing provisions in s. 47 of the CCA.

6.3.1 There is evidence of monopoly pricing

Throughout the Inquiry, market participants raised a number of concerns about the ability of pipeline operators to exercise market power when negotiating the price of transportation services and claimed that the prices charged for some services are excessive and higher than would be expected in a workably competitive market, or under regulation. These concerns centred on¹¹⁶:

- the rates of return that pipeline operators expect to earn on the incremental investments outlined in section 6.1, which have formed the basis for setting the transportation charges payable by users of these investments
- the prices that are being charged by pipeline operators that have already recovered the cost of building the pipeline
- the prices some pipeline operators are charging for as available, interruptible, back haul and bi-directional services.

The Inquiry has investigated these concerns and found that there is some substance to the claim by market participants that a large number of pipeline operators are engaging in monopoly pricing and that the prices that are being charged for some services are excessive. Perhaps the most telling indicators of the excessive prices that are being charged for some services come from the pipeline operators' internal documents, which reveal the following about some of the more significant pipelines owned by four different pipeline operators, all of which are currently unregulated:

- One major arterial pipeline is earning 70 per cent more in revenue than the pipeline operator estimated it would be earning if it was regulated.¹¹⁷
- The EBIT return on asset (measured on a historic cost, written down asset value basis) earned by one major pipeline that faces some degree of competition has been over 20 per cent p.a. between 2013 and 2015.¹¹⁸
- Another major pipeline that faces some degree of competition expects to generate an internal rate of return of 19 per cent on a recent investment that has been fully underwritten by a shipper.

115 For example, for gas flowing from Victoria to Wallumbilla APA could offer a bundled price for use of the SWQP/QSN with the central route (DTS/MSP) that is lower than the prices that would be payable for use of the individual legs of this route, or could offer a lower SWQP/QSN price to customers that also use the DTS/MSP leg. If the total price for the route was lower than the price of using the western route (MAPS/SEA Gas) and the SWQP/QSN (priced as an individual leg) or the eastern route (the EGP/MSP) and the SWQP/QSN (priced as an individual leg) then it could foreclose competition.

116 Concerns have also been raised by some market participants about the fees that are being charged for some ancillary services (for example, renomination charges, capacity trading, in-pipe trades and in-pipe redirection services), which they claim cost little to provide and just amount to 'clipping the ticket'.

117 This pipeline, like other transmission pipelines, has existing contracts in place that would be unlikely to be affected by any decision to regulate the pipeline because provisions within the NGL protect pre-existing contractual rights.

118 This return has been estimated using the pipeline operator's estimate of the written down value of the pipeline and EBIT values over those years.

- One pipeline operator that is facing declining volumes is trying to maintain a rate of return that is 1.5 times higher than it estimated it would be able to earn if it was subject to regulation.

The Inquiry recognises that high profits are not necessarily reflective of market power and that no one piece of evidence is definitive in demonstrating that pipelines are exercising market power when negotiating with shippers. However, the totality of the evidence gathered through the Inquiry **combined** with the lack of competitive constraints faced by most pipelines is highly indicative of the exercise of such power.

Further detail on the Inquiry's findings is provided below. Note that it was beyond the scope of this Inquiry to carry out a detailed forensic examination of the prices charged by every pipeline on the east coast to determine whether they involve the exercise of market power. Instead, the Inquiry has investigated the concerns that were raised by market participants about particular prices. In doing so, the Inquiry has had regard to GTAs, invoices, board papers, financial information and a range of other internal documents provided by pipeline operators in relation to the major arterial pipelines on the east coast (namely, the SWQP/QSN, RBP, MSP, EGP, MAPS, SEA Gas Pipeline, DTS and TGP) and a sample of other smaller pipelines (namely, the BWP, CGP and SEPS).

The high returns pipelines expect to earn on incremental investments are consistent with monopoly pricing

As outlined in section 6.1, significant investment has been carried out by APA, Jemena and Epic over the last two to three years to expand, connect and/or develop bi-directional capability on regulated and unregulated pipelines and on pipelines that are, strictly speaking, subject to some degree of competition. These investments range in value from around \$10 million to \$120 million.

Chart 6 sets out the returns on equity that the various pipeline operators expect to earn on these incremental investments, which have formed the basis for setting the transportation charges payable by users of these investments. The returns presented in this chart have been obtained from internal documents provided by the pipeline operators, which in most cases were prepared to obtain board approval for the proposed expenditure, or the prices to be paid by shippers. Given the commercially sensitive nature of this information, the Inquiry has decided not to publish the names of the projects.

To put these returns into perspective, chart 6.1 includes the benchmark return on equity that the AER has used over the last three years when determining the revenue requirement of pipelines that are subject to full regulation under the NGR¹¹⁹, which has ranged from 7.1 per cent to 8 per cent.¹²⁰ The Inquiry has used this as a benchmark because under the NGR, the return on equity used in the calculation of a regulated service provider's revenue requirement must be commensurate with the efficient financing costs of a benchmark efficient entity that faces a similar degree of risk to that faced by pipeline operators and reflect the prevailing conditions in the market for equity funds.

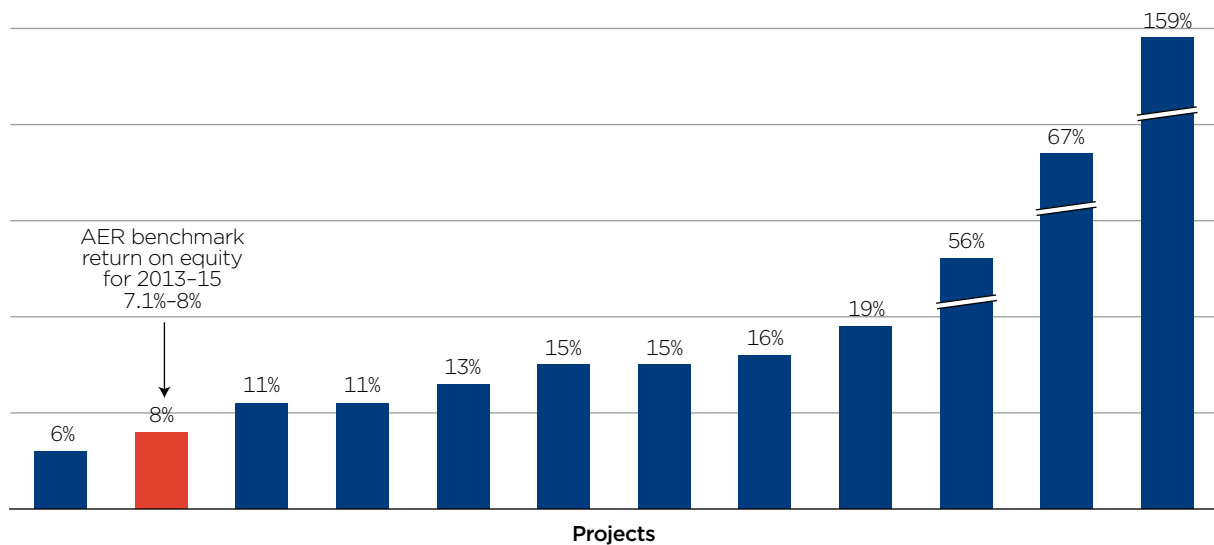
While high rates of return may be warranted in cases where the level of risk associated with an investment is high, the incremental investments have, as noted in section 6.1, largely been

¹¹⁹ Under the regulatory framework set out in the NGR, the revenue requirement of a pipeline that is subject to full regulation is determined using the building block methodology, which involves summing the cost components (building blocks) that a prudent and efficient service provider would incur in providing reference services over the regulatory period (that is, the return on capital, depreciation, operating expenditure and net tax liabilities). One of the key cost components in the building block methodology is the rate of return, of which the return on equity is one element. In keeping with rule 87(2) of the NGR, the AER is required to determine the rate of return in a manner that achieves the following objective:
"...the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services."
 Rule 87(7) also states that the in estimating the return on equity, regard must be had to the prevailing conditions in the market for equity funds.

¹²⁰ Over the last three years, the AER's regulatory decisions on the return on equity have ranged from 7.1 per cent to 8 per cent. See AER, *Final Decision: Jemena Gas Networks Access Arrangement 2015-20, Attachment 3, June 2015*, p. 3-10 and AER, *Final Decision: APA GasNet Australia (Operations) Access Arrangement 2013-17, Attachment 2, March 2013*, p. 55. Note that while Jemena appealed the AER's decision on the return on equity, it was not successful in this appeal. See *Application by Jemena Gas Networks (NSW) Ltd [2016] ACompT5 [95]*.

underwritten by users who have entered into medium- to long-term GTAs with the relevant pipeline operator. The demand risks associated with these investments are therefore relatively low and do not explain the relatively high returns depicted in chart 6.1.

Chart 6.1: Return on equity expected to be earned on recent incremental projects¹²¹



As chart 6.1 shows, the expected return on equity on these projects ranges from 6 per cent to 159 per cent. With the exception of one of these projects, the expected return on these projects is 1.4–20 times *higher* than the return on equity benchmark estimated by the AER. The majority of the returns are also far higher than the return on equity that was adopted in the winning bid for the NGP.

The differences between the returns depicted in this chart, the return on equity estimated by the AER and the return adopted in the winning bid for the NGP are substantial and are consistent with the significant degree of market power that existing pipeline operators can use when negotiating the prices to access incremental projects.

The difference between these expected returns and the return assumed in the winning bid for the NGP also reflects the fact that competition for the development of a new pipeline (that is, competition for the market) is generally considerably stronger than it is for incremental investments in existing pipelines. In contrast to new pipelines, the natural monopoly characteristics of pipelines means that it is usually far cheaper to augment an existing pipeline than it is to build another pipeline to provide any additional services that may be required (including bi-directional services). There is therefore little prospect for competition in the provision of incremental investments, which explains why their rates of return are in the majority of cases so much higher than the return assumed in the NGP winning bid.

While not shown in chart 6.1, the returns towards the upper end of this range are expected to be earned on investments in bi-directional capability. These investments are expected to yield a high return because the cost of the conversion is relatively small and it allows the pipeline to earn revenue on flows in both directions.¹²² It also reflects the fact that the pipelines in question have been fully underwritten through long-term GTAs on the basis of forward haul, as one pipeline operator noted:

“The equity return [...] reflects the incremental nature of the reverse [...] flow of the [...] Pipeline, which was originally fully funded on the basis of [foundation contracts].”
[insertion added]

¹²¹ This chart only includes projects where the pipeline operator reported the project’s expected return on equity. There were two other projects that didn’t report the expected return on equity, with one project expecting to generate an internal rate of return of 19 per cent and the other pipeline expecting to earn a post-tax project return of over 15 per cent.

¹²² Note that some of the deliveries may occur by displacement rather than physically being transported.

The additional profit is being retained by the pipeline operators, which is why they expect to earn returns in the order of 55–160 per cent for bi-directional investments.

Internal documents also reveal that in most cases the pipeline operators have sought to recover the cost of the incremental investments over the life of the shipper's GTAs, rather than the life of the asset, to minimise their risk exposure. These pipeline operators are therefore exposed to very little demand risk, with the only material risk being that users default on their commitments.

The prices charged by pipelines that have already recovered the cost of construction are higher than would be the case under full regulation

During the Inquiry, concerns were raised by a number of market participants about pipeline operators that had recovered the cost of constructing the pipeline¹²³ (or a large portion thereof) not reducing transportation charges to reflect this recovery and therefore 'over recovering' the cost of construction. The three examples that market participants cited in this context included one major arterial pipeline and two smaller pipelines. In each of these cases, market participants claimed that the prices paid by foundation users of these pipelines had been set to provide for the accelerated recovery of the cost of constructing the pipeline and that once this occurred prices should just be based on the cost of operating the pipeline.

The owners of the three pipelines were provided an opportunity to respond to these concerns and were also asked to provide their views on whether prices should be reduced if the cost of constructing the pipeline had already been recovered from users. The pipeline operators in question responded by noting that past recoveries of capital are less relevant to the determination of prices because prices are established through commercial negotiations, which are forward-looking in nature. Elaborating on this further, one pipeline operator stated the following:

"The financial treatment or valuation methodologies employed on most assets...have little correlation with the original construction costs. Foundation customers may receive price reductions after a commercially negotiated time period, however once these contracts have reached the end of their term, new prices will be developed based on inputs,...future operating profile, replacement costs and commercial market signals."

Another pipeline operator noted that:

"...the tariffs and associated non-price terms of access for our pipelines are subject to various forward-looking considerations and constraints, such as:

- the delivered price of gas to the destination market or markets by means of one or more alternative pipelines;*
- the extent to which upstream producers that are able to inject gas into these pipelines benefit from buyers with choices as to which end market gas is to be shipped;*
- the extent of spare capacity on both the principal and each alternative, competing pipeline;*
- the prices prevailing under existing, long term take or pay commitments by existing shippers;*
- the extent to which existing shippers (on either the principal or any alternative, competing pipeline) hold spare capacity under contract, and so are able to compete to provide that spare capacity to third parties; and*
- across all of these variables, the extent to which the present, highly dynamic nature of the east coast gas market may cause them to change over the relevant period for which any new transportation contract price is to be struck."*

¹²³ The term 'construction cost' is used here to refer to the original cost of developing the pipeline and any costs incurred in expanding, extending or otherwise modifying the pipeline, including a return on those investments.

The third pipeline operator noted the following:

“For pipelines subject to either light or no regulation, tariffs have no relationship with the capital costs of a pipeline and are a derivation of market forces, with light regulation providing for an AER dispute resolution process if negotiation of tariffs fails. In such a process, there is no requirement for pipeline tariffs to be determined by reference to unrecovered capital costs and [...] considers that such an approach may not be consistent with a number of the revenue and pricing principles which are applicable.”

The views expressed by these pipeline operators are at odds with the views expressed by shippers, as highlighted in the following statement made by Central Petroleum in a submission to the AEMC’s East Coast Gas Market Review¹²⁴:

“In Central’s case, gas reserves sold into the East Coast market need to be transported along the Amadeus Gas Pipeline (AGP), the newly announced NGP, and then down the Carpentaria Gas Pipeline (CGP). Whilst tariffs for the NGP have been established and are clearly linked to actual costs and investments for a new build, the AGP and CGP are existing pipelines (of several decades) with previous gas transportation agreements having already underwritten the investment. As mentioned above, pipeline transportation tariffs, particularly in the case of mature existing pipelines, appear out of sync with actual operating costs and reasonable investment returns.”

Kimberly-Clark Australia (KCA) expressed similar views about this type of behaviour in its application to the NCC for the SEPS to be regulated.¹²⁵

The Inquiry recognises that a range of factors may result in a pipeline operator being able to ‘over recover’ the cost of construction. Many have little to do with the exercise of market power. For example, an unexpected increase in demand later in the life of a pipeline may enable it to ‘over recover’ its construction costs even if it faces effective competition. Equally the pipeline could ‘under recover’ if demand was unexpectedly low, though the chances of this are reduced by the use of long-term GTAs.

While this is the case, if the pipeline was subject to full regulation under the NGL and NGR, the scope to charge prices that ‘over recover’ the cost of providing the service would be limited because one of the more fundamental principles in the NGR is that an asset should only be depreciated once over its economic life.¹²⁶ In effect, this means that once the value¹²⁷ of the asset has been recovered from users, regulated prices would be based on the forward looking cost of operating and maintaining the pipeline (including the cost of carrying out any future capital works). This principle was adopted in at least two of the GTAs that were provided to the Inquiry, with provisions in these GTAs providing for prices to fall once the cost of construction had been recovered.¹²⁸

The Inquiry has examined the concerns raised by market participants by comparing the prices currently being charged by the pipelines in question with the prices that could be expected to prevail if the pipelines were subject to full regulation. In doing so, the Inquiry has used a discounted cash flow model and a combination of publicly available information and material provided in the Inquiry to determine whether the costs incurred in the construction of these

124 Central Petroleum, *Submission to AEMC Pipeline Regulation and Capacity Trading Discussion Paper*, 15 February 2016.

125 KCA, *Application for Coverage of a Pipeline*, October 2012.

126 See r. 89(1)(d) of the NGR.

127 The way in which an asset would be valued if it was subject to full regulation will depend on whether it was commissioned prior to the commencement of the Gas Code in late 1997 or after this date. Specifically:

- For pipelines commissioned before the Gas Code came into effect, s. 8.10 specifies 11 factors that the regulator may take into account when setting the value, which, includes amongst other things the depreciated actual cost (DAC), the depreciated optimised replacement cost (DORC), a recent sales price and the circumstances of that purchase, the basis on which tariffs have been (or appear to have been set in the past), the economic depreciation of the pipeline and the historic returns to the pipeline operator. Section 8.11 further states that the value should not normally fall outside the range set by the DAC and the DORC.
- For pipelines commissioned after the Gas Code came into effect, ss. 8.12–8.13 of the Gas Code state that the initial capital base is to be based on the actual costs incurred in the construction of the pipeline plus capital expenditure, less redundant assets and less depreciation and capital contributions.

128 In both of these cases the GTAs were agreed to as part of a foundation contract that was entered into before the pipeline was developed.

three pipelines have been recovered from users. The key inputs into this model included estimates of the costs incurred in the construction and operation (that is, capital expenditure, operating expenditure, depreciation, tax and a rate of return) of the pipeline and the revenue earned to date.

The results of this modelling revealed that two of the pipelines have already recovered the cost of construction from users¹²⁹, while the other has recovered a substantial proportion of these costs (~85 per cent) and is expected to recover the remainder in the next five years.

Using information provided by the pipeline operators, the Inquiry has estimated what the prices would be if the pipelines were subject to full regulation and prices were based on the forward looking cost of operating and maintaining the pipelines, as the NGR require. This analysis indicates that the prices on the two pipelines that have already recovered their cost of construction are 2–5 times higher than they would be likely to be if they were subject to full regulation.

The prices charged by some pipelines for as available, interruptible and backhaul services are excessive

As gas flows become more dynamic throughout the east coast the demand for as available¹³⁰, interruptible¹³¹, backhaul¹³² and bi-directional services and other ancillary services is increasing, particularly amongst gas fired generators, LNG projects and producers. Financial data provided by the pipeline operators indicates that this is a growing source of revenue for some pipelines. It is also contributing to a substantial increase in the profitability of those pipelines where the costs have been underwritten by long-term foundation contracts, because unlike the US where revenue from these services would be used to reduce the firm transportation rate, pipeline operators are retaining the benefit.

During the Inquiry, concerns were raised by market participants about the prices that a number of pipeline operators are charging for these services, with some noting that the prices are excessive and are discouraging flows of gas into the southern states. Similar concerns have also been raised in the context of the AEMC's East Coast Gas Market Review.

The Inquiry has investigated these claims using the indicative benchmarks set out in box 6.2.

129 In one of these cases, the Inquiry was able to corroborate its findings with statements from an annual report, which indicated that the prices in the foundation contract had been set to recover the construction costs over an accelerated period of time in line with the expected life of the fields used to supply the location. This assumption was also reflected in the price path that had been adopted in the foundation agreement.

130 An as available service, as its name suggests allows a buyer to transport gas without reserving and having to pay for capacity on a daily basis, subject to the availability of capacity. The priority accorded to this service is lower than that accorded to a firm transportation service.

131 Like an as available service, an interruptible service also allows a buyer to transport gas without reserving and paying for capacity on a daily basis, but the priority accorded to this service is usually lower than the as available service, so the pipeline operator can curtail the service if it becomes capacity constrained, or higher priority services are required.

132 A back haul service involves the notional 'transportation' of gas in the opposite direction to the predominant flow of gas. The transportation is notional because the service does not actually result in the physical transportation of gas in the opposite direction. Rather the service involves a physical swap with gas 'exchanged' at the point at which it is intended to enter the pipeline for an equivalent amount of gas at the backhaul delivery point. The practical effect of the back haul service is that the net forward haul flow is offset by the volumes of gas nominated for back haul. If there is an insufficient volume of gas being transported on a forward haul basis then the back haul service will be interrupted, which is why this service is usually only sold on an interruptible basis.

Box 6.2: Benchmarks for as available, backhaul and bi-directional prices

The benchmarks set out in this box are indicative only and should not be construed as an endorsement by the Inquiry of the pricing levels implied by these benchmarks.

As available and interruptible services

There is no well-accepted regulatory principle for the pricing of as available or interruptible services in Australia, but the principle that has been adopted in the EU and the US is that the price of as available or interruptible services should not exceed the price of firm capacity.¹³³
¹³⁴ The Inquiry has therefore used this as a benchmark.¹³⁵

In Australia, firm capacity charges tend to be payable on the basis of reserved capacity, while as available and interruptible charges are payable on the basis of actual volumes transported. So if a customer with a firm transportation service only transports 77 per cent of its reserved capacity on a day (that is, a 130 per cent load factor), the price payable on a per GJ of gas transported basis would be equivalent to a 130 per cent firm capacity charge.

To develop an equivalent as available and interruptible price that can be used as a benchmark to assess the prices being charged by each pipeline, the Inquiry has used data from the Bulletin Board to calculate the five year average load factor for each pipeline. The average ranged from 115–200 per cent. Using the pipeline with a 115 per cent load factor as an example, if the pipeline was charging more than 115 per cent of the firm capacity charge for as available services this could be viewed as excessive (that is, because it is higher than the equivalent price for firm capacity).

Back haul services (non-physical)

Like as available and interruptible services, there is no well accepted regulatory principle for the pricing of back haul services in Australia, but the Inquiry is aware that the AER's predecessor, the ACCC, has previously approved backhaul tariffs that are 50 per cent lower than the forward haul tariff.¹³⁶ In the EU, the Agency for Cooperation of Energy Regulators has stated that the price for this service should be set to reflect the actual marginal (additional) costs that the pipeline operator incurs to provide this service and shall not be below zero.¹³⁷

While the principle adopted in the EU has merit, the Inquiry is not in a position to estimate the incremental costs of providing this service, so for the purposes of assessing the prices that pipelines are currently charging for back haul services, the Inquiry has employed the 50 per cent of forward haul tariff benchmark that has previously been adopted by the AER.

Bi-directional services

In a similar manner to as available, interruptible and back haul services there is no well accepted regulatory principle for the pricing of bi-directional services in Australia. The Inquiry is aware, however, that in the US interstate pipelines charge the same price for these services as firm forward haul services and any additional revenue derived from these services is taken into account in the calculation of the firm rate (that is, the benefit of being able to 'transport' greater volumes of gas and the fuel cost savings that arise because some deliveries occur via displacement rather than transportation, are passed on to shippers).

For the purposes of assessing the prices that pipelines are currently charging for bi-directional services, the Inquiry has decided to employ a similar principle to that used in the US. That is, the bi-directional price should be no greater than the firm forward haul capacity charge.

Using these benchmarks, the Inquiry has found the following:

- The as available and interruptible charges levied by most pipelines are lower than would be implied by multiplying the pipeline's average load factor by the firm transportation charge. There are, however, three major pipelines that are charging considerably more than this benchmark under some GTAs, with prices for as available or interruptible services ranging from 185 per cent to 350 per cent of the firm transportation charge on these pipelines. These charges are excessive and suggest that the pipelines in question face little constraint in the pricing of these services, including from primary capacity holders who should, in principle, be able to compete to provide similar services (see chapter 8).
- The back haul charges currently being paid by shippers are either less than or equal to the benchmark set out in box 6.2 (that is, 50 per cent of the forward haul tariff). The Inquiry, however, was informed by one market participant that it has recently received an offer for a back haul service on two key pipelines where the rate was set equal to the forward haul rate, which is considerably higher than the benchmark.
- The bi-directional¹³⁸ charges levied by two pipelines were higher than the cost of the forward haul service but in both cases the contracts were relatively short term in nature and in one case the GTA provides for the price to fall if the shipper exercises an option to extend the contract term. In contrast to the US, there is no evidence that any of the pipeline operators that are offering bi-directional services have reduced the prices payable on forward haul services to reflect the additional revenue that they are recovering from these services, which is why the rates of return that pipeline operators expect to earn on these projects are so high.

Pipeline monopoly pricing is occurring

To summarise, there is evidence that a large number of pipelines are taking advantage of their market power by engaging in monopoly pricing, with ten of the 11 pipelines that were investigated having been found to be engaging in some or all of the behaviours outlined above,

133 Article 14.1(b) of Regulation (EC) No. 715/2009 states that the price of interruptible capacity shall reflect the probability of interruption. This regulation has been interpreted by the Agency for Cooperation of Energy Regulators in Europe as requiring the price of interruptible capacity to be sold at a discount to the firm capacity price, with the level of the discount to reflect the risk (likelihood and duration) of interruptions, so that if the risk of interruption is low the discount should be low and vice versa. ACER, Framework Guidelines on rules regarding harmonised transmission tariff structures for gas, November 2013, p. 33.

134 In the US, the price of interruptible services on interstate pipelines regulated by the Federal Energy Regulatory Commission (FERC) is capped at the firm rate, but any revenue derived from these services must be taken into account when calculating the firm rate so the pipeline doesn't recover more than the allowed revenue.

135 This benchmark may overstate the amount that needs to be recovered from the pipeline operator if the primary capacity has been fully contracted (or a large portion has been contracted), because the pipeline operator will already be recovering the fixed costs of operating the pipeline from primary capacity holders.

136 ACCC, East Australian Pipeline Ltd Access Arrangement: Moomba to Sydney Pipeline System, 2 October 2003, p. 200.

137 ACER, Framework Guidelines on rules regarding harmonised transmission tariff structures for gas, November 2013, p. 33.

138 The term 'bi-directional' is used in this context to refer to both a service that enables gas to go in both directions, or a service that enables gas to go in the opposite direction to the predominant flow of gas but which is not necessarily a back haul service because the pipeline flow can change if required.

in addition to other forms of monopoly pricing. The ten pipelines include, in no particular order, the SWQP/QSN, BWP, RBP, CGP, MSP, EGP, SEPS, MAPS, DTS and TGP.¹³⁹

As this list highlights, some of the pipelines that were found to be engaging in monopoly pricing are, strictly speaking, subject to some degree of competition (that is, the MSP, EGP and MAPS) while others are subject to full or light regulation (that is, the RBP, DTS, CGP and half of the MSP). This finding reinforces the observation that competition is not posing as an effective constraint on the behaviour of pipeline operators as might be expected and that the gas access regime, in its current form, is also failing to impose an effective constraint on pipeline operators, either directly through regulation or indirectly through the threat of regulation. Further detail on why the gas access regime is not constraining the behaviour of pipeline operators can be found in chapter 7.

While there is no doubt that the changes underway on the east coast have provided some pipeline operators with a greater opportunity to engage in this behaviour, the Inquiry has found a number of examples of pipelines engaging in this behaviour before the changes commenced.¹⁴⁰ The monopoly pricing observed by the Inquiry should not therefore be viewed as transitory in nature. Rather, it reflects the enduring market power that a large number of pipelines on the east coast possess and the incentive and ability they have to exercise that market power when setting prices.

It has been contended by some pipeline operators that pipeline charges have only been increasing by inflation. The Inquiry has found that the prices specified in longer-term GTAs have tended to only rise in line with inflation, in line with the price escalation provisions only allowing for a CPI based escalation over the contract term. However this does not eliminate the potential for monopoly pricing. Where the initial prices in a GTA are set at monopoly levels, then increases to these prices at the rate of inflation will tend to keep these prices at or near monopoly levels. Where the initial prices in a GTA are set at a level more consistent with competitive outcomes, these provisions may limit the pipeline operators' opportunity to move from competitive pricing levels to monopoly pricing levels over the contract term. However the evidence gathered through the Inquiry indicates that pipeline operators have engaged in such behaviour when entering into new GTAs, or when some existing shippers have sought an amendment to their existing contracts to obtain new services.

6.4 Monopoly pricing by pipelines adversely affects economic efficiency

Monopoly pricing by pipeline operators can adversely affect market participants because:

- it results in lower ex-plant gas prices for producers and/or higher delivered gas prices for users
- it can cause significant transfers of wealth from producers, users and consumers to the pipeline operators.

Monopoly pricing can also have adverse consequences for the efficient operation of the gas market and economic efficiency in upstream and downstream markets, because it can result in:

- lower than efficient levels of gas use and investment in downstream facilities
- lower than efficient levels of gas production and investment in gas exploration and reserves development
- inefficient utilisation of pipelines and potential distortions in gas flows across the market, which can prevent gas from flowing to where it is valued most.

¹³⁹ The pipeline that was found not to be engaging in any of these forms of behaviour was the SEA Gas Pipeline, the capacity of which has been fully contracted under three long-term foundation contracts. The presence of these long-term GTAs means that the pipeline operator has been unable to engage in monopoly pricing. See <http://apa.com.au/our-business/energy-infrastructure/south-australia.aspx>.

¹⁴⁰ For example, at least one pipeline operator has been charging relatively high as available charges for some time and one of the pipelines was found to have recovered its construction costs in 2010.

6.4.1 Monopoly pricing by pipelines affects gas prices

Monopoly pricing by a pipeline operator can result in:

- producers receiving less for the gas they supply (lower ex-plant gas prices)
- industrial users paying more for the gas they use (higher delivered gas prices)
- end-users paying more for gas and electricity and paying more for products that require gas in their production (higher prices for end-users).

The effect of monopoly pricing on each of these prices, and in turn on economic efficiency, largely depends on the alternatives available to producers, users and consumers. Monopoly pricing by pipelines can also have an indirect effect on the price paid for gas by users that don't directly use a particular pipeline. In the southern states in particular, pipeline charges affect the alternatives gas producers and gas users face when they negotiate prices with each other. So monopoly pricing on a pipeline can affect price bargaining outcomes for gas delivery that may not use that pipeline (an indirect price effect).

Factors affecting the ex-plant price of gas (direct effect)

Higher transportation charges can lower the ex-plant price of gas. If users can source gas from elsewhere then producers facing higher transportation charges may have to lower their ex-plant price to remain competitive.

The two key factors that will affect the impact of monopoly pricing on the ex-plant price of gas are the alternatives available to producers at one end of the pipeline and the alternatives available to users at the other end.

The impact of monopoly pricing on the ex-plant price of gas will be **larger** if:

- producers cannot commercially 'avoid' the pipeline by sending some or all of their gas to another destination using a different pipeline
- users can commercially 'avoid' the pipeline—that is, they can obtain gas supplies from producers supplying from different gas fields and using different pipelines.¹⁴¹

The ability of a producer or a user to commercially 'avoid' the pipeline will depend on a number of factors, including the cost of producing the gas and the cost of delivering the gas to its destination. In some cases, it may be technically feasible for gas to be sent to a number of destinations, but it may only be commercially viable, or commercially attractive, to send it to one destination.¹⁴²

The effect of lower ex-plant prices on the volume of gas supplied will depend on whether a producer is able to earn a sufficient return to induce it to supply gas (or continue to supply). This will depend on whether the producer has made significant sunk investments to facilitate the production of gas.

If the producer has made these investments, substantial falls in the ex-plant price may be necessary before the volume of gas supplied into the market is affected, at least in the short term. In this case, there is scope for large transfers of wealth from producers to the pipeline operator. If those investments have not yet been made, and gas supplies are dependent on new investments in exploration and development, then a fall in the ex-plant price has the potential to cause significant reductions in the volumes of gas produced.

Factors affecting the delivered price of gas (direct effect)

The same two factors outlined above will also affect the impact of monopoly pricing on the delivered price of gas. The impact of monopoly pricing on the delivered price of gas will be **larger** if:

- users cannot commercially 'avoid' the pipeline—that is, they have no alternative but to purchase gas that is delivered to their location via the pipeline

¹⁴¹ This assumes that the other pipeline has a different owner and is not also engaging in monopoly pricing. If the other pipeline is also engaging in monopoly pricing, the ex-plant price of gas is likely to be affected on both pipelines.

¹⁴² Due to the long distances to other destinations for instance.

- producers can commercially ‘avoid’ the pipeline by sending some or all of their gas to another destination using different pipelines.¹⁴³

Again, the delivered price of the gas may mean that ‘avoiding’ the pipeline may not be commercially viable or commercially attractive for a producer or a user, even if avoidance is physically possible.

The effect of higher delivered gas prices on the volume of gas used will depend on at least two factors. One is the alternatives to using gas. If users have made significant sunk investments that ‘tie’ the user to gas as an energy source or feedstock, then substantial increases in the delivered price may be necessary before volumes of gas used are substantially affected. The other is the ability of retailers, industrial users and GPGs to pass on the higher delivered prices to end users. If a user manufactures products for export, or faces import competition, then it may have little scope to pass on the higher cost of delivered gas if it is a price taker in that market. If the user supplies products to domestic consumers the scope to pass on higher delivered gas prices is likely to be greater.

Higher prices for end-users (direct effect)

Monopoly pricing by pipelines can directly affect the level of gas use by affecting the delivered price of gas—with higher delivered prices generally leading to reduced levels of gas use. In addition there is another less direct effect—in the event that monopoly pricing reduces the ex-plant price of gas, and this reduces the volume of gas produced, it will have the effect of increasing the price of gas in the market. All other factors remaining the same, less gas available for domestic use will result in higher domestic gas prices.

To the extent that retailers, industrial users and GPGs pay more for gas, it will ultimately be reflected in higher prices for the products that they or their customers supply. As a result, over the long term, monopoly pricing of pipelines will lead residential customers to pay more for gas and electricity and for other end-users to face higher prices for products that use gas in their production.

High transportation charges on some pipelines can also affect gas prices in the southern states even if users don’t utilise those pipelines (indirect effect)

As discussed in chapter 2, gas prices in Queensland are now shaped by the LNG netback prices as a result of the introduction of the export option in the east coast gas market. However, domestic gas users in the southern states face a different pricing dynamic created by the distance separating the domestic users and producers in the south from the export facilities in Queensland. As shown in chart 2.4, the cost of transportation between Wallumbilla and the user’s location is creating a range of possible gas pricing outcomes in the southern states, encapsulated by the gap between the buyer and seller alternatives (capped at the buyer’s maximum willingness to pay and with a floor of the marginal cost of supply). As discussed in chapter 2, the GBJV is likely to charge domestic users in the southern states a price approaching the buyer’s alternative in the absence of genuine competitive constraints.

Chart 6.2 illustrates the impact pipeline charges are likely to have on gas pricing outcomes in the southern states in this environment. The top and bottom solid lines represent the buyer and seller alternatives in a scenario where transportation charges on all pipelines on the route between Wallumbilla and the buyer’s location are set at a monopoly level. The two middle dotted lines represent the buyer and seller alternatives in the scenario where transportation charges on the same route are reduced significantly from the monopoly pricing level. Importantly, the transportation charges on this route impact on the pricing outcomes in the negotiation between the parties even if the parties do not intend to use any of the pipelines on this route (for example, because gas is coming from Victoria rather than from Wallumbilla).

¹⁴³ This assumes that the other pipelines have a different owner and is not also engaging in monopoly pricing. If the other pipeline is also engaging in monopoly pricing, the delivered price of gas is likely to be affected on both pipelines.

Chart 6.2 Impact of reduced transportation costs on the bargaining framework for gas supply negotiations in the southern states

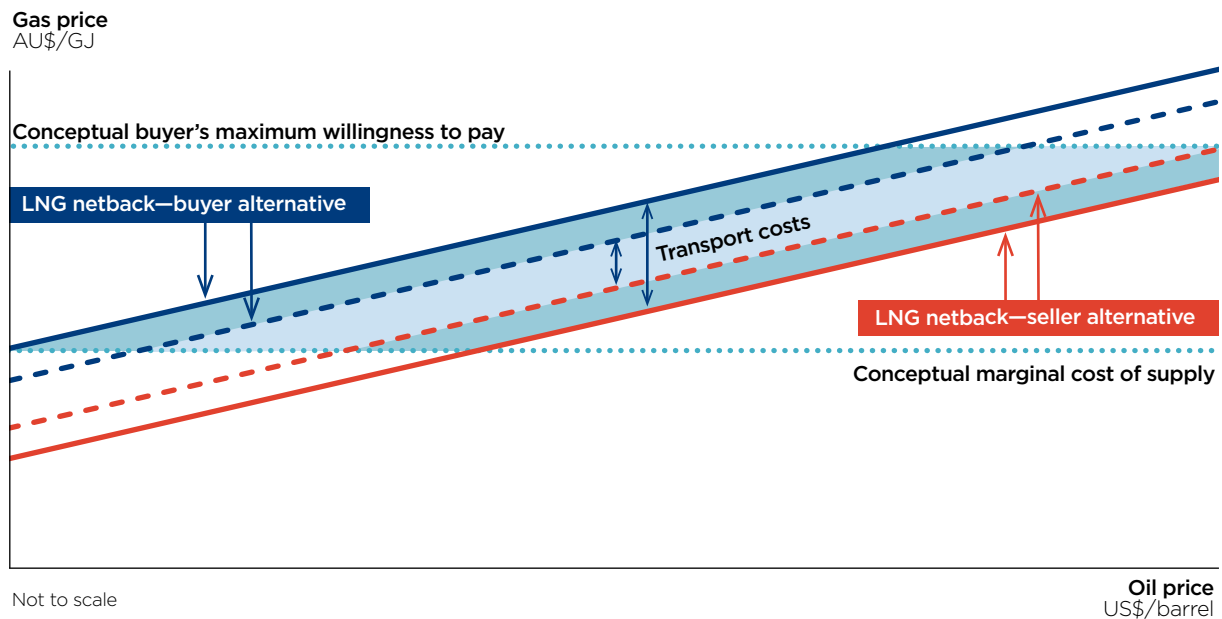


Chart 6.2 shows that reducing transportation charges is likely to result in a narrower range of possible pricing outcomes for domestic users in the southern states (the space between the two dotted lines), with:

- the maximum price the buyer would be willing to pay falling because it costs less to transport gas south
- the floor price for the seller rising because the reduction in the transportation cost means it is more attractive to export gas.

Critically, in an environment where domestic gas users in the southern states are likely to pay a price approaching the buyer's alternative, the maximum price they may have to pay is reduced. The greater the difference between the monopoly transportation charges and efficient transportation charges on the relevant pipelines, the greater is likely to be the adverse impact of inefficient monopoly pipeline pricing on domestic gas pricing outcomes in the southern states.

Table 6.2 shows the impact of reducing transportation charges payable on the MSP and SWQP/QSN on the LNG netback prices in Sydney using the same assumptions as those in the example set out in box 2.3 in chapter 2. Table 6.2 shows three scenarios where the transportation charges on these pipelines are reduced by 10 per cent, 25 per cent and 50 per cent from their current levels. These transport charge reduction levels are for illustrative purposes only, because the Inquiry has not estimated the levels of pipeline prices, or of pipeline price reductions, that would be considered efficient. The price reductions of 10–50 per cent are considered of interest given that:

- One pipeline estimated that it was earning 70 per cent more in revenue than it believes it would if it was regulated, which would imply approximately a 40 per cent reduction in prices if the firm moved to its estimate of revenue under regulation.
- On two pipelines that have already recovered their construction costs, pipeline charges were 50–80 per cent higher than a charge based solely on the cost of recovering the forward looking cost of operating and maintaining the pipeline.

Table 6.2 Scenario Analysis—Likely effect of reduction in transportation charges on the buyer’s alternative price in Sydney (AUD\$/GJ)

	Transportation Charges Scenarios			
	Current Charges	10 per cent Reduction	25 per cent Reduction	50 per cent Reduction
LNG netback price at Wallumbilla		\$6.69		
Transportation fuel costs		\$0.04		
Transportation charges for SWQP/QSN (west) and MSP (Moomba to Wilton)*	\$2.03	\$1.83	\$1.52	\$1.02
LNG netback price Sydney—Buyer’s Alternative	\$8.76	\$8.56	\$8.25	\$7.75
Reduction in buyer’s alternative		\$0.20	\$0.51	\$1.02

Note: The transportation charges in this table are the same as those used in box 2.3.

Table 6.2 shows that reducing transportation charges by 10–50 per cent could lead to a \$0.20–\$1.02 difference in the maximum price payable by domestic users in the southern states.

6.4.2 Monopoly pricing by pipelines affects efficiency

It is widely recognised that the exercise of market power may reduce economic welfare. This might occur, for example, where a pipeline with market power raises the transport price above the long-run average cost of supply, reducing the volume of gas delivered.

These higher prices lead to an inefficiently low level of use of gas because monopoly pricing has the effect of restricting use only to those users with a willingness to pay of at least that price. This leads to an inefficient allocation of the economy’s resources across sectors and firms as the level of economic activity making use of gas will be below its efficient level. For example, domestic users will not use gas at the efficient level; investment decisions will be affected and energy use decisions between GPG and coal fired generation will be distorted. This kind of ‘allocative efficiency’ is a key reason behind the economic regulation of some other monopoly infrastructure servicing domestic demand, for example, electricity transmission and distribution networks.

However, in some cases the price paid to transport gas may have little or no impact on the demand for pipeline services. This might occur, for example, where the gas is exclusively sold on a world market (for example, in the form of LNG) at a competitive world market price, and that price is materially above the cost of existing domestic gas production. Alternatively, this might occur where a gas user is reliant on gas as a feedstock or energy source and is unable to substitute to other fuel sources without a major re-configuration of plant. In both of these cases, due to the lack of alternatives, the volume of gas transported may not vary over a range of possible pipeline charges. In these cases, the demand for pipeline services is said to be highly ‘inelastic’ in response to a change in the price. Another situation where the pipeline price has no impact on the volume of gas transported is where the pipeline can price discriminate between customers, charging each customer an amount just short of the amount which would induce that customer to reduce gas production (in the case of a producer) or switch to an alternative fuel (in the case of a gas consumer). In such cases a change in pipeline charges merely brings about a ‘wealth transfer’ between pipeline users (for example, gas producers or consumers) and the pipeline.

While it is sometimes said that a pure wealth transfer has no impact on overall economic welfare and therefore is not a relevant policy consideration, the circumstances are rare in practice and do not apply in the east coast gas market. The Inquiry considers that due to a lack of information about the demand for pipeline services, price discrimination is seldom ‘perfect’ in practice, especially where the pipeline owner sells to a gas retailer rather than selling directly to downstream customers. In addition, gas is not exclusively sold on a world market at a competitive world market price. While some users may have inelastic demand over a short period, there are many different users, with a variety of demand responses to different prices.

As previously noted, exercising market power through monopoly pricing is legitimate commercial behaviour. In a market economy guided by the profit motive this should be expected. Pipeline operators have an incentive to transport the volume of gas that will maximise their profits. However, doing so in a way that does not ultimately reduce volume is likely to be difficult:

- Where pipeline operators offer a single price, the profit maximising volume is likely to be less than the volume of gas that would be produced and used in the absence of monopoly pricing. In the situation where a single price is offered, demand is likely to respond to changes in that price, especially over time or where there are many users with different levels of willingness to pay.
- Where pipelines offer multiple prices in an attempt to price discriminate, any such attempt is unlikely to avoid reductions in quantity supplied into the market. Price discrimination by pipeline operators between different gas users is likely to be difficult. It is hard to accurately assess the effect of a price point on volume for an individual user. In addition, in many situations, the pipeline operators are not selling directly to the end user but instead are selling to a retailer that then sells to an industrial customer. The pipeline operators cannot easily see the impact of their higher pipeline charges on these end users as they do not deal directly with them.
- Where pipelines offer multiple prices in an attempt to price discriminate it is also difficult for them to accurately assess the effect of a price point on volume for an individual gas producer.

Pipeline operators are unlikely to be able to accurately assess the impact of their pricing on the ex-plant price of gas and the delivered price of gas. They are unlikely to be able to accurately assess the impact of those price changes on the willingness of producers to supply gas and willingness of gas users to use gas. Yet this would be needed to have a situation where monopoly pricing had no impact on the volume of gas produced and used in the market.¹⁴⁴

Even a static or short-run situation where a simple wealth transfer might conceivably occur ignores the effect of the potential exercise of market power on the incentives for investment upstream and downstream.

Upstream and downstream customers will almost always be required to make material sunk investments. For example, producers make substantial investments in exploration and development of gas fields and in the processing of gas; gas users make investments in plant and equipment which uses gas as an energy source or as a feedstock. These investments are subject to the threat of hold-up: the risk that, once sunk, the pipeline will raise its charges, expropriating the value of these investments. Both pipeline operators and shippers recognise this risk and seek to mitigate it, typically by entering into long-term GTAs before making major investments.¹⁴⁵ As this Inquiry confirms, all major pipeline investments in Australia have been largely or entirely underwritten through long-term GTAs with major customers.

However, long-term GTAs are not a perfect solution to this problem. Long-term GTAs are inevitably incomplete. Over time circumstances arise which were not anticipated at the outset. The location of major gas sources and major gas consumers may change over time, bringing new customers to seek access to the pipeline which were not present at the time of construction. In addition, for reasons of transaction costs small 'mass market' customers cannot enter into such long-term GTAs directly.

¹⁴⁴ It is open to regulators to be concerned with consumer welfare in the rare case where monopoly pricing is having little or no effect on allocative efficiency.

¹⁴⁵ Pipelines are also subject to the threat of hold-up. Once a pipeline is built, it can't be redeployed to another route and has few alternative uses. A shipper could ask for a pipeline to be built, but once the pipeline is built the shipper could then refuse to pay more than a price that just covers the pipeline operator's variable costs. Once the pipeline is built the pipeline operator may have little choice but to accept, since the fixed capital costs of the pipeline are sunk and it may be able to do little else with the asset. Knowing this the pipeline operator may be unwilling to invest in building the pipeline in the first place. Long-term contracts can help reduce the hold-up problem by specifying in advance of investments how prices will be formed and other rules and criteria will be applied.

It follows that while long-term GTAs can provide adequate protection to the interests of the initial (foundation) customers for a period of time, beyond this period of time upstream and downstream users are increasingly subject to a threat of hold-up from existing pipelines. This reduces their incentive to invest and foregoes some of the potential gains from trade.

This hold-up effect gives rise to lower than efficient levels of investment. This effect can potentially be reduced through some form of control on the ability of pipelines to exercise market power by raising prices.

6.4.3 Monopoly pricing of gas pipelines affects downstream market efficiency

Monopoly pricing of gas pipelines affects downstream usage

The previous section highlighted how monopoly pricing of pipelines can affect the delivered price paid for gas by industrial users and consumers. These higher prices lead to an inefficiently low level of use of gas.

The Inquiry has heard specific examples from market participants of excessive transportation charges affecting gas use and investment in downstream facilities. Through the Inquiry a number of users noted that excessive transportation charges can limit the potential opportunity for bringing gas from the Northern Territory or Queensland into the southern states, or from Victoria into Queensland.

A report by Deloitte Access Economics in 2014 noted that higher delivered gas prices will cause reduced output and redistribution of resources and economic activities to other states.¹⁴⁶ Public examples of actual and potential impacts given in that report attributable to rising delivered gas prices were potential impact on prices for Orica's Ammonia facility (in NSW), with a likely shutdown should it not be able to access the cheap Strike gas it had invested in along with reductions in production at Rio Tinto Aluminium's Queensland Yarwun Alumina refinery. Also, in 2013 CSR announced the closure of its Ingleburn glass factory, citing as a factor that increasing energy and manufacturing costs in Australia have exacerbated Viridian's competitive position relative to imports.¹⁴⁷

While these examples focused on the delivered price of gas, the commodity price will, as noted above, be influenced by transportation costs because of the buyer-seller netback framework (see table 6.2). Australian Paper stated to a recent Victorian inquiry that all of its investment in Victoria is currently at risk due to the failure of the gas markets to provide long-term competitively priced gas to manufacturers and industry.¹⁴⁸ The Inquiry heard similar comments from other Victorian industrial users during the course of the Inquiry.

Whilst these examples are focused on the commodity price change, including through the influence of transportation charges on southern commodity gas pricing, changes in the overall delivered price via changes in the transportation charge, would also be expected to affect gas usage.

Pipeline pricing reduces downstream investment via holdup

In downstream markets, investments in facilities that use gas, such as GPGs, industrial facilities and LNG plants, can be significant and often irreversible. If the pipeline operator appropriates most (or even all) of the 'economic surplus' from the facility once the investment has been made then it may also result in underinvestment in these facilities, lower levels of output from these facilities and less innovation. For example, this could occur if the transportation charge is set as high as the difference between the price the facility receives for its end-product and the variable cost of producing that product. The risk of this occurring is greatest when there is only one pipeline that the facility can viably use.

146 Deloitte Access Economics, *Gas market transformations—Economic consequences for the manufacturing sector, A report to the Australian Industry Group and others*, July 2014, available at: <http://www2.deloitte.com/au/en/pages/economics/articles/australian-gas-market-transformations.html>.

147 CSR media release, 'Restructure of Viridian glass operations and trading update', 11 March 2013.

148 Australian Paper, *Submission 648 to the Inquiry into Onshore Unconventional Gas in Victoria*; available at <http://www.parliament.vic.gov.au/epc/inquiry/406>.

If users have some choice about where to locate, or require a new pipeline to be developed to service their location, then the ability of the pipeline operator to engage in this behaviour may be constrained to some extent by competition. Users in this case may be able to reduce their exposure to this risk by entering into long-term GTAs before they invest. If, however, the length of the GTA does not perfectly align with the life of the investments, then they will be exposed to the risks outlined above when their contracts end (that is, the risk of hold-up). They may also be exposed to this risk if more capacity is required over the term of the GTA than has been contracted. This highlights a more fundamental problem with long-term GTAs, which is that it is not possible to cover all possible outcomes in a GTA. So even if there is a GTA in place, a user may be exposed to the risk of hold-up.

If, on the other hand, users have no choice about where they locate and there is an existing pipeline in place, then they will be exposed to the risks outlined above over the life of the investment.

Evidence received through the Inquiry indicates that GTAs in most cases are not linked to the life of the upstream and downstream investments, so the risk outlined above is a genuine risk faced by market participants. Shippers also provided some examples of cases where they have an existing GTA, but variations to the GTA have resulted in monopoly pricing.

- In Tasmania, despite \$6 million in federal funding being set aside for an extension of the gas distribution system from Port Latta to Smithton, evidence indicates that pricing by the transmission pipeline operator, influenced in-turn by negotiations with its main customer, Hydro Tasmania, contributed to the extension not occurring. That is, the Inquiry considers that the pipeline offered prices, which were around 200 per cent higher than they had been in the past (that is, because the pipeline operator was trying to recover the revenue it expected to lose as a result of Hydro Tasmania reducing its MDQ post-2017), and that this contributed to the project not proceeding.
- In regional South Australia, KCA runs a tissue factory, which receives gas supply on the SEPS on which it was a foundation customer from 1990 until the contract expired in 2010. The foundation contract charged prices on a sliding scale with charges higher in the beginning years and lower in the years after which the capital cost to build the pipeline was assumed to be recovered. The SEPS was initially regulated but became unregulated in 2000 following an application by Epic Energy (under different ownership to the current ownership) in 2000. After the contract expired in 2010, the 'old' Epic significantly increased the prevailing tariff. KCA applied to have the SEPS regulated ('covered') in 2012 and noted in its application a number of benefits it perceived from obtaining coverage, including:
 - that coverage was required to maintain its competitive position in the market and survive as a manufacturer in the region
 - that coverage should stimulate demand for gas in the downstream market, leading to greater throughput on the SEPS and more efficient utilisation of the pipeline
 - that coverage would encourage greater diversity of supply by the likes of Beach Energy, which could displace Origin's position as a dominant retailer to regional areas.

Notwithstanding the benefits cited by KCA, both the NCC and South Australian Minister for Mineral Resources and Energy found that the SEPS failed to meet the coverage criteria because it could not be shown that access or increased access to the pipeline was likely to promote a material increase in competition in another market.¹⁴⁹ The SEPS therefore remains unregulated.

¹⁴⁹ NCC, *Final Recommendation—Application under the National Gas Law for a coverage determination for the South Eastern Pipeline System*, 8 April 2013, p. 10, and South Australian Minister for Mineral Resources and Energy Hon. T Koutsantonis, *Decision of the Relevant Minister to Section 99 of the NGL in relation to an application for coverage of the South East Pipeline System*, 13 October 2013.

Pipeline prices affect whether or not gas gets to its highest value use

The construction and operation of the LNG plants means that transportation charges also have the potential to affect the allocation of resources between domestic gas use and gas export. Where pipeline prices exceed long run average costs they can lead to an inefficient allocation of resources between the domestic use of gas and the export of LNG. Prices on different pipelines have different effects on the level of gas use for domestic purposes versus gas use for export, because different pipelines service these different demand centres.

If domestic pipelines are engaging in monopoly pricing but the LNG pipelines are not, then this could result in gas that would otherwise have been supplied into the domestic market being diverted to spot LNG sales, even if the gas has a greater value if used domestically. Table 6.2 above indicates that a 50 per cent reduction in firm prices on the SWQP/MSP south would reduce prices by around \$1/GJ on that route meaning effectively that the LNG spot price could be up to \$1/GJ lower but gas still flow to domestic users. As noted also in chapter 8, as available and interruptible pricing on the SWQP/MSP is in excess of \$3/GJ which means in shorter-term excess supply situations (for example, an LNG train is offline or LNG spot prices are persistently low), then a reduction in as available and interruptible pricing by \$1.50 (50 per cent) for example, increases the chance that gas will flow to domestic markets. This in turn could affect domestic market depth and liquidity.¹⁵⁰

Transportation charges, penalties and ancillary service charges that incorporate some element of monopoly pricing can also affect the efficient utilisation of pipelines and prevent gas from flowing to where it is most highly valued by affecting the prospects for trading.

For example, if pipelines connected to trading markets, including on the SWQP and MSP to Sydney, the SWQP and MAPS to Adelaide, and the RBP to Brisbane, are engaging in monopoly pricing, this could affect the liquidity of trading on the STTMs where gas is bought and sold at a market-clearing price. It will lead to a higher delivered gas cost, and reduce the profits that a supplier would be able to obtain by selling gas via those mechanisms. It could render the sale of gas via those mechanisms entirely unviable for a particular supplier, particularly one that is located further from the market than another supplier. Further, if monopoly pricing impacts on southern routes (that is, through the SWQP) are greater than on the RBP, then this could result in gas staying in Brisbane (or gas-powered generation in the region), even if the gas has a greater value in the southern states.

6.4.4 Monopoly pricing of gas pipelines affects upstream market efficiency

Monopoly pricing of gas pipelines can affect production

As noted above, transportation charges that incorporate some element of monopoly pricing are likely to reduce the ex-plant price received by producers.

A lower ex-plant price is likely to make marginal gas supplies uncommercial. Lower production of gas will result in lower levels of gas use in the domestic market and/or fewer exports. Either is a lost opportunity that would otherwise enhance economic growth and welfare.

The Inquiry has heard specific examples from market participants of excessive transportation charges affecting exploration and production.

For example, during the Inquiry one producer that is seeking to supply gas from the Northern Territory to the east coast noted an inability to negotiate contracts for the transport of gas beyond Mt Isa with existing pipelines that reasonably reflect the costs of providing those services (specifically back haul within existing mature pipelines). The pipelines in question provide the only alternative for the producer to transport its gas to the east coast market. The producer claims the transportation charges offered appear excessive and do not reflect the reasonable costs associated with providing those services, most notably back haul uncontracted capacity. This is making the supply of gas beyond Mt Isa uncommercial and further exploration for gas into the east coast unjustified. The producer added that the high transportation charges have a

¹⁵⁰ AGL commented on the impact of transmission pricing on market depth and liquidity in its Response to Harper Review Draft Report, 21 November 2014, p. 7

negative impact on a producer's ability to raise capital for new gas exploration and development capital for proven reserves.

The Inquiry is also aware of at least two other prospective producers in the southern states whose future production levels are likely to be influenced by the transportation charges levied by the pipelines they are connected to, both of which have been found to be engaging in monopoly pricing.

A further particular risk is evolving in the east coast gas market, where the prices that some producers are receiving are linked to oil prices and the prices in GTAs are fixed for the term of the GTA. In this environment, a GTA that was entered into when the oil price was US\$70 per barrel may, if the gas producer is responsible for paying the transportation charge, result in the producer receiving less than the cost of production if the oil price falls to US\$30 per barrel. While the GTA may have originally been struck at a (monopoly) price that made the production of gas commercial, it may have the unintended effect of limiting gas supplies as circumstances change. A GTA originally struck at a lower (competitive) price may have had less of a later consequence on gas supplies.

Pipeline pricing reduces upstream investment via holdup

Gas exploration and the development of gas reserves can be expensive and risky. In order for these activities to be commercial, the expected profits from successful projects must outweigh the expected losses from unsuccessful projects. If the pipeline operator appropriates most (or even all) of the 'economic surplus' from the producer (that is, by setting the transportation charge as high as the difference between the cost of producing the gas once the gas reserves have been proven and the value of the gas at the end location) then it may result in underinvestment in gas exploration and development.

Where producers have some choice about where to locate, or require a new pipeline to be developed to service their location, then the ability of the pipeline operator to engage in this behaviour may be constrained to some extent by competition. However producers may often be limited in their choice about where to locate, as the location of gas fields is largely fixed and a producer may not have the control of multiple fields that might allow such a choice. Where a new pipeline is required to service their location producers have much greater opportunity to reduce their exposure to this risk by entering into long-term GTAs before they invest.

As noted above, the length of the GTA may not perfectly align with the life of the investments and the risks of hold-up remain when their contracts end. If producers have no choice about where they locate and there is an existing pipeline in place, then they will be exposed to the risks outlined above over the life of the investment. Evidence received through the Inquiry indicates that GTAs in most cases are not linked to the life of the upstream and downstream investments, so the risk outlined above is a genuine risk faced by producers.

Identifying specific examples of upstream investment that do not occur solely due to the risk of hold-up is difficult. However, the Inquiry is satisfied that hold-up, or the potential for hold-up, has been a factor in the examples relating to upstream investment discussed in this section, and that the potential for hold-up is likely to be a key concern of prospective investors in upstream exploration and production.

7 Strengthening the gas pipeline access regime will improve economic efficiency in the gas market and related markets

Given the apparent pervasiveness of monopoly pricing and the detrimental effect this type of behaviour can have on economic efficiency in the upstream and downstream markets and on consumers more generally, it is relevant to consider why the existing gas access regime is not imposing more of a constraint on the behaviour of pipeline operators.

The gas access regime was implemented by state and territory governments almost 20 years ago. At the time the regime was implemented, with the exception of one or two smaller pipelines, all the transmission pipelines¹⁵¹ on the east coast were deemed to be covered and subject to economic regulation. Less than 20 per cent of transmission pipelines are now subject to any form of regulation. This is in stark contrast to other comparable international jurisdictions such as the US, New Zealand (NZ) and the EU, where the vast majority of transmission pipelines are subject to economic regulation.

Not only are few transmission pipelines currently regulated, but the threat of regulation is also failing to impose an effective constraint on the behaviour of a number of unregulated pipelines. This is because the current test for regulation under the NGL is not targeted to the right market failure (that is, monopoly pricing that results in economic inefficiencies). Also, other gaps in the regulatory framework and information asymmetries are:

- allowing pipelines that are subject to regulation to continue to engage in monopoly pricing
- limiting the ability of shippers to identify the exercises of market power and to negotiate effectively with pipeline operators.

Put simply, the gas access regime in its current form is not constraining the behaviour of pipeline operators in the manner that policy makers intended. Nor is it contributing to the attainment of the overarching objective of the regime, the National Gas Objective (NGO), which is to¹⁵²:

“promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.”

To address these issues, the Inquiry recommends a number of changes to strengthen the gas access regime and ensure that it is fit for purpose, targeted and proportionate to the market failure identified in this Inquiry, and consistent with the NGO.

7.1 How pipelines are regulated in Australia and other jurisdictions

7.1.1 Australia’s gas access regime was originally implemented to provide a constraint on the behaviour of pipeline operators

The gas access regime was originally implemented by state and territory governments in 1997 through the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code). The stated objective of the Gas Code was the establishment of a framework for third party access to gas pipelines that would, amongst other things, prevent the abuse of monopoly power by pipeline operators and provide rights of access on fair and reasonable terms for both the pipeline operator and users.¹⁵³

Following the independent review of the strategic direction for energy market reform that was chaired by Warwick R. Parer, the Productivity Commission’s 2003–04 review of the gas access regime, and the 2006 Expert Panel report on energy access pricing, COAG decided to implement a new legal, governance and regulatory framework. This new framework commenced on 1 July

151 One of the transmissions pipelines that was not regulated at this time was the Cheepie to Barcardine Pipeline.

152 This objective is set out in s. 23 of the NGL.

153 *National Third Party Access Code for Natural Gas Pipeline Systems*, November 1997, p. 1.

2008 and was given effect via the NGL and NGR. While many aspects of the original regime were retained in the NGL and NGR, a number of important refinements were made to reduce the risk of regulatory error, the cost of regulation and regulatory related investment risks, including:

- the inclusion of an objects clause (the NGO) and revenue and pricing principles¹⁵⁴ in the NGL, which were implemented to provide decision makers with greater guidance on the matters to be considered when making decisions and to limit the risk of regulatory error
- the introduction of a 15-year no-coverage option for greenfields pipelines, which was implemented to counter the adverse effect regulation may otherwise have on greenfield investment^{155, 156}
- the introduction of a lighter handed regulation option, which was implemented to minimise regulatory costs and reduce the risk of regulatory error in cases where the pipeline's market power is constrained in some way.

Under the current regime, regulation 'coverage' applies if:

- the pipeline was deemed to be a covered pipeline when the Gas Code came into effect
- a coverage application is made to the National Competition Council (NCC) and the relevant Minister, having regard to the NCC's recommendation, is satisfied the pipeline meets all the coverage criteria set out in s. 15 of the NGL (see box 7.2)
- an unregulated pipeline voluntarily submits an access arrangement to the AER, or
- the pipeline is developed through an AER approved tender process.

The access regime also provides for:

- coverage to be revoked if at least one of the coverage criteria is not satisfied
- a pipeline's coverage status to change over time if circumstances change
- greenfields pipelines to be granted a 15-year exemption from coverage if one or more of the coverage criteria are not satisfied.

If a pipeline is covered, then it may be subject to either full or light regulation (see box 7.2). The difference between these two forms of regulation can be summarised as follows:

- **Full regulation:** A pipeline subject to full regulation must periodically submit a 'full access arrangement' to the AER and obtain its approval for the proposed price and non-price terms and conditions of access that will apply to the reference service(s) (a service that is sought by a significant portion of the market) over the regulatory period. When assessing the proposed access arrangement, the AER is required to have regard to the relevant provisions in the NGR and the revenue and pricing principles in the NGL. Although AER approval of an access arrangement is required, the pipeline operator and shippers on contract carriage pipelines can still enter into agreements that differ from the approved arrangement.
- **Light regulation:** This form of regulation is more akin to the negotiate-arbitrate model with greater emphasis placed on commercial negotiation and information disclosure and the AER only playing a role if the dispute resolution provisions are triggered. A light regulation pipeline is also prohibited from engaging in inefficient price discrimination or other conduct that may adversely affect access or competition in other markets.

The NGL also includes a merits review mechanism, which is designed to minimise the risk of regulatory error in relation to coverage, form of regulation and access arrangement decisions. In addition to this safeguard, the NGL protects pre-existing contractual rights and allows parties to reach alternative arrangements to those set out in an access arrangement. The protection of contractual rights means new pipelines and other investments can still be underwritten by shippers through medium- to long-term GTAs, which reduces regulatory related investment risks.

154 These principles, which are set out in s. 24 of the NGL, state amongst other things that the pipeline operator should be provided a reasonable opportunity to recover at least the efficient costs of providing services, the rate of return should be commensurate with the regulatory and commercial risks involved in providing reference services and regard should be had to the costs and risks of under and over investment and under and over utilisation of a pipeline.

155 A 15-year no-coverage application can also be made for a major extension of an existing pipeline that is not a covered pipeline, or a light regulation pipeline if the extension has been exempted by the AER.

156 This option was incorporated into the gas access regime in 2006.

Box 7.1: Independent reviews of the gas access regime

Parer Review—Towards a Truly National and Efficient Energy Market (2002)

In 2001, COAG agreed to commission an independent review of the strategic directions for energy market reform in Australia. The review was conducted by an independent Panel, which was chaired by Warwick Parer. In the course of this review, concerns were raised about the effect that regulation can have on investment in greenfields pipelines. To address this concern, the Panel recommended that greenfield pipelines be allowed to seek a 15-year binding ruling that the pipeline be unregulated. In doing so, the Panel noted such a ruling would 'eliminate any regulatory disincentives (perceived or otherwise) for new pipelines for the first 15 years of operation and should remove the potential incentive to 'undersize' pipelines to minimise regulatory risk.'¹⁵⁷

Productivity Commission—Review of the Gas Access Regime (2003–04)

In 2003, the Commonwealth government asked the Productivity Commission to review the gas access regime. In its final report, the Productivity Commission raised a number of concerns about the potential for regulation to lead to inefficient investment because of regulatory error, regulatory risk and asymmetric truncation and recommended the following to address these concerns¹⁵⁸:

- introducing an overarching objects clause and clear pricing principles to guide decision makers
- allowing lighter handed regulation when a pipeline does not exert substantial market power
- allowing greenfields pipelines to obtain a binding 15-year no-coverage ruling if they do not meet the coverage criteria to 'reduce the potential chilling effect of regulation' on these investments.

Expert Panel on Energy Access Pricing (2005–06)

In 2005, the Ministerial Council on Energy established the Expert Panel on Energy Access Pricing to advise on the harmonisation of revenue and network pricing in gas and electricity. Like the Productivity Commission, the Expert Panel recommended the introduction of a light handed regulatory option.¹⁵⁹ It also endorsed the proposed 15-year regulatory holiday for greenfields pipelines because it considered the risk of regulatory error to be greatest for greenfields pipelines given demand growth is uncertain. The Expert Panel also found the potential for and consequences of regulatory error in relation to mature pipelines is much less pronounced and recommended the risks be dealt with by ensuring that 'the objective for the regulator is appropriate, the guidance is clear and that the mechanisms in place for review of the regulator's decisions are appropriate.'¹⁶⁰

157 Parer, W R, *Towards a Truly National and Efficient Energy Market*, 2002, p. 255.

158 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. xxii.

159 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 51.

160 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 81.

Box 7.2: Coverage criteria and form of regulation decisions

Coverage criteria

The coverage criteria in the NGL require the NCC and the relevant Minister to consider whether:

- access (or increased access) to the services provided by means of the pipeline would promote a material increase in competition in at least one other market (criterion (a))
- it would be uneconomic to develop another pipeline to provide the services provided by means of the pipeline (criterion (b))
- access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety (criterion (c))
- access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest (criterion (d)).

In deciding whether or not the coverage criteria are satisfied, the NCC and Minister are required to have regard to the NGO.

Form of regulation decisions

The NCC is responsible for deciding whether a pipeline should be subject to full or light regulation. In making such a decision, the NCC is required by section 122 of the NGL to consider:

- the likely effectiveness of full and light regulation in promoting access
- the effect of full and light regulation on the costs that may be incurred by an efficient service provider, efficient users and prospective users, and end-users.

The NCC is also required to have regard to the form of regulation factors, the NGO and any other matters it considers relevant. The form of regulation factors require consideration to be given to:

- the presence and extent of any barriers to entry in a market for pipeline services
- the presence and extent of any network externalities (i.e., interdependencies) between a service provided by the pipeline operator and any other natural gas services it provides, or any other service it provides in other markets
- the extent to which any market power possessed by a service provider is, or is likely to be, mitigated by any countervailing market power possessed by a user or prospective user
- the presence and extent of any substitute, and the elasticity of demand, in a market for a pipeline service in which a pipeline operator provides that service
- the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be)
- the extent to which there is information available to a prospective user or user, and whether that information is adequate, to enable the prospective user or user to negotiate on an informed basis with a pipeline operator for the provision of a pipeline service.

Like a coverage decision, the form of regulation applied to a particular pipeline can be altered over time if conditions change.

7.1.2 Gas pipelines in other comparable jurisdictions are generally subject to regulation

Table 7.1 provides a brief overview of the regimes that have been put in place to regulate gas pipelines in NZ, the EU and the US.

Table 7.1: Regulation of gas pipelines in other jurisdictions

	NZ	EU	US
Description of transmission pipeline industry	There are two major transmission pipelines in NZ, both of which are regulated.	There are a large number of transmission pipelines in the EU, which are required to offer services on a non-discriminatory basis and are subject to regulation by national regulatory authorities. Most pipelines are regulated but some that run parallel to other pipelines are not.	The US gas market consists of multiple transmission pipelines between supply basins and distant demand centres most often located interstate. All major interstate transmission pipelines are regulated unless the pipeline operator can demonstrate that it lacks significant market power. No pipelines have been able to demonstrate this to date.
Economic Regulator	Commerce Commission	National regulators and the Agency for Cooperation of Energy Regulators	Federal Energy Regulatory Commission (FERC) (for interstate pipelines)
Background to the introduction of regulation	Regulated under the current Part 4 of the Commerce Act since 2008. The New Zealand Government's decision to regulate followed a review by the <i>Commerce Commission in 2003-04 under the pre-2008 Part 4 of the Commerce Act 1986</i> , which involved an assessment of whether the services provided by pipelines are supplied in a market in which competition is limited and if regulation is necessary or desirable in the interests of pipeline users. The Commerce Act now provides for non-exempt transmission and distribution pipelines to be regulated and subject to information disclosure and the default -customised price-quality path form of regulation.	Member states have been responsible for regulating transmission pipelines for some time. Through the Second Gas Directive and Regulation 1775 in 2002, the EU required member states to regulate access to transmission pipelines and tariffs to be transparent and non-discriminatory and reflect the actual costs incurred. In 2009 the Third Gas Directive and Regulation 715 required the vertical separation of transmission from production and retail, the introduction of the entry-exit model and the development of EU wide network codes on a range of matters, including third party access.	The initial decision to regulate in the 1930s followed 'financial abuses' of large multi-state vertically integrated pipeline/distribution companies. In 1935 the Public Utility Holding Company Act required interstate pipelines to divest distribution, the 1938 the Gas Act invoked accounting regulation. Further changes occurred in the 1980s following gas shortages in the 1970s and perceived inefficiencies in pricing. For example, FERC Order 436 resulted in buyers no longer having to buy gas and transportation on a bundled basis, while FERC Order 636 required all pipelines to convert to third party access, prevented bundled sales and required separation of pipeline operators from supply affiliates.

	NZ	EU	US
Key features of the regulatory regime	<p>Regulated pipelines are subject to:</p> <ul style="list-style-type: none"> • Economic regulation of non-contestable services • Information disclosure regulation • The Commerce Act also includes a list of exempt pipelines. A pipeline can be added to this list if the Minister is satisfied its services are supplied in a market where the pipeline does not have a substantial degree of market power and vice versa. <p>In addition, operating codes overseen by the co-regulatory industry body set out ring-fencing protocols and non-price terms and conditions of access.</p>	<p>Regulated pipelines subject to:</p> <ul style="list-style-type: none"> • Economic regulation of non-contestable services • Limited information disclosure • Network codes, which, amongst other things, set out the rules relating to third party access, capacity allocation/ congestion management, tariff structures, balancing and trading. 	<p>Interstate pipelines are subject to:</p> <ul style="list-style-type: none"> • Economic regulation of non-contestable services provided by existing and new pipelines • Significant information disclosure requirements, which amongst other things require pipeline operators to disclose operating and financial and information and contract prices. <p>Before a new interstate pipeline can be developed in the US, it must be authorised by FERC. Authorisation will usually be granted if the developer can show it is underpinned by long-term contracts. The new pipeline will automatically become subject to regulation, with the prices and terms and conditions of access set out in the foundation GTAs becoming the default for regulated tariffs.</p> <p>Interstate pipelines can apply to FERC to charge 'market based' (unregulated) rates. Under the framework FERC has developed, a pipeline will only be allowed to charge market based rates if it can demonstrate it does not have significant market power.</p>

As table 7.1 highlights, the regimes in each jurisdiction are quite bespoke, but there are some important features in common:

- the majority of transmission pipelines in these jurisdictions are subject to a comprehensive form of economic regulation
- information disclosure is a key element of most of these regimes, although the level of disclosure is greater in the US where information transparency is seen as critical to enabling shippers to negotiate effectively and also limit the scope for price discrimination
- all non-contestable services are subject to regulation.

The first of these features is notable given that in the US and the EU, most supply sources and demand centres are serviced by more than one pipeline yet economic regulation is widespread. As the Brattle Group noted in a report to the NCC¹⁶¹:

“Most supply basins in North America and Europe have more than one pipeline accessing them. Many destination markets have multiple pipelines serving them. Despite the greater ‘thickness’ of these markets, pipelines in these jurisdictions are still considered to have natural monopoly characteristics and are regulated with respect to price and terms and conditions of service.”

Another noteworthy point is that the decision to regulate or to revoke regulation in these jurisdictions has not turned on whether access will promote a material increase in competition in another market as it does in Australia. It has instead tended to turn on whether the pipeline has a substantial degree of market power and the ability and incentive to exercise that power.

For example, in NZ the Commerce Commission is required to consider whether the ‘gas pipeline services are supplied in a market where the owner has a substantial degree of market power’ when making a recommendation to the Minister on whether a pipeline should be added to, or deleted from, the list of exempt pipelines in the *Commerce Act 1986* (NZ).¹⁶²

In the US, a slightly different approach has been taken, with the operators of new and existing interstate pipelines presumed to have substantial market power and regulation only being removed if the pipeline operator can demonstrate it lacks significant market power.¹⁶³ That is, the pipeline operator must show that it lacks the power to profitably maintain prices above competitive levels for a significant period of time. When evaluating such an application, the Federal Energy Regulatory Commission (FERC) will consider:

- the market in which the pipeline services are provided
- the pipeline’s market share, the degree of market concentration and the potential for the pipeline operator to act together with other pipelines to raise prices¹⁶⁴
- whether there are any constraints on the pipeline operator’s market power, including the availability of ‘good alternatives’¹⁶⁵, the potential for entry, the countervailing power of shippers and any other constraints on the ability or incentive to exercise market power.

While provision has been made in the US for regulation to be revoked, all the interstate pipelines remain regulated and subject to full regulation by FERC.

161 Brattle Group, *Competition in Gas Pipeline Markets: International Precedent for Regulatory Coverage Decisions*, June 2000, p. 4.

162 *Commerce Act 1986* (NZ) s. 55A.

163 FERC, *Alternatives to Traditional Cost-of-Service Rate-making for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC, 1996.

164 FERC uses the Herfindahl-Hirschman Index (HHI) to measure market concentration and applies a threshold of 1800, below which it applies less scrutiny. This threshold implies four to five good alternatives to the applicant’s service.

165 A ‘good alternative’ is defined by FERC as having a price low enough, quality high enough and being available soon enough to permit substitution.

7.2 Limitations in the gas access regime mean it doesn't provide an effective constraint on pipelines

At the time the Gas Code was implemented all but one of the transmission pipelines in the east coast were deemed to be covered and subject to full regulation. In the intervening period, coverage has been revoked¹⁶⁶ on all but 4.5 transmission pipelines and one new pipeline has become covered through a competitive tender process.¹⁶⁷ There are now just 5.5 covered pipelines in the east coast, three of which are subject to full regulation (that is, the DTS, RBP and CRP) and 2.5 to light regulation (that is, the CGP, CWP and the MSP south of Marsden).¹⁶⁸ Appendix 4 provides more detail on the regulatory status of transmission pipelines on the east coast and how this has changed over time.

The reduction in the number of regulated pipelines over the last 18 years provides some insight into the diminishing influence that the gas access regime is having on transmission pipelines. So do the findings in the preceding chapter on monopoly pricing and the limited influence the regime is having on the behaviour of regulated and unregulated transmission pipelines.

The reasons why the regime is having little influence on the behaviour of pipelines are three-fold:

- first, the coverage criteria establish a hurdle for regulation that is unlikely to be met by the majority of transmission pipelines on the east coast given the characteristics of the east coast gas market. The criteria are also, as the Productivity Commission has noted, not designed to address the market failure that has been observed in this Inquiry, which is monopoly pricing that gives rise to economic inefficiencies with little or no effect on the level of competition in dependent markets
- second, there are a number of features of the regulatory framework that are, in effect, allowing pipelines that are subject to full regulation to still engage in monopoly pricing
- third, there is limited publicly available information on the costs incurred by pipeline operators in providing services or on the relationship between these costs and the prices charged for services, which is limiting the ability of shippers to identify any exercise of market power.

Further insight into why the gas access regime is not constraining the behaviour of pipeline operators can be found in the following statement in AGL's submission to the Harper Review¹⁶⁹:

"It is AGL's current experience that extended regulation of monopoly transmission providers and gas transmission network pricing is needed. Even with increasing interconnection, the disparity of bargaining power between pipeline operators and shippers is leading to economically inefficient outcomes and negatively impacting market depth and liquidity..."

¹⁶⁶ In the case of the SWQP and QGP coverage was revoked by the Queensland Government in the transition to the NGL and NGR, by making a regulation, rather than through a formal assessment of whether the two pipelines satisfied the coverage criteria. By the same regulation, the Queensland Government changed the form of regulation on the CGP to light regulation and has prohibited any change in this regulatory status being made until the end of 30 April 2023.

¹⁶⁷ The CRP became covered through a competitive tender process rather than an application of the coverage criteria. Under the NGL, a proponent of a pipeline has an option to use terms and conditions of access accompanying a competitive tender process for the construction of a pipeline as the regulated terms and conditions of access for the pipeline. The compliance process for this requires proposing terms and conditions of access in a tender, providing certain documentation for the AER in a compliance report. At least six months prior to the commissioning of a tender approval pipeline, the service provider (successful tenderer) must submit a proposed access arrangement which reflects the proposed terms and conditions of access.

¹⁶⁸ The MSP between Moomba and Marsden is unregulated because the Commonwealth Minister for Industry, Tourism and Resources was not satisfied that criterion (b) was met on this part of the pipeline when it considered APA's application for the revocation of coverage of the MSP in 2003.

¹⁶⁹ AGL, *Response to Harper Review Draft Report*, 21 November 2014, p. 7.

“The disparity of bargaining power arises because pipelines remain, practically speaking, monopoly infrastructure. Most pipelines are ‘uncovered’, and not subject to economic regulation. While coverage, or the threat of coverage, theoretically operates as a constraint to pipeline operators in their commercial negotiations with shippers, pipeline coverage is actually hard to obtain and, once obtained, tends to lead to an access arrangement with only limited scope. For example, operators of ‘covered’ pipelines have historically only been required to offer one reference service (typically a standard firm forward haul service), while the prices and terms for remaining services remain subject to one-sided bilateral negotiation. This inequality of bargaining power is exacerbated as shippers/retailers are generally tied to a pipeline, based on their long-term upstream gas supply decisions.”

During the Inquiry a number of other shippers also noted the lack of constraint posed by the existing regime and pointed to the failure of the SEPS to satisfy the coverage criteria as evidence of the regime’s inability to constrain the behaviour of pipeline operators even when the pipeline in question is a monopoly and there is evidence of monopoly pricing. Another shipper informed the Inquiry that it had been advised that a major arterial pipeline that it uses, which is not subject to competition from another pipeline, was also unlikely to satisfy the coverage criteria. This advice was consistent with expert advice that the pipeline operator obtained, which was provided to the Inquiry and which noted that the pipeline was unlikely to satisfy the coverage criteria because access was unlikely to result in a material increase in competition in another market.

The observations made by AGL and other shippers in this context are consistent with the Inquiry’s findings and highlight the need for the regulatory regime to be strengthened so that it can pose a more effective constraint on the behaviour of pipeline operators, as policy makers originally intended.

7.2.1 The coverage criteria are not directed to the right market failure

The coverage criteria in their current form largely mirror the declaration criteria in Part IIIA of the CCA. Like Part IIIA, an application for a pipeline to become covered must show that the pipeline is uneconomic to duplicate (criterion (b)) and that access is required to promote a *material* increase in competition in upstream or downstream markets (criterion (a)). It must also show that access can be provided without undue risk to human health and safety (criterion (c)) and that access would not be contrary to the public interest (criterion (d)).

The criterion that has proved most difficult to satisfy in pipeline coverage and revocation of coverage decisions over the last 19 years is criterion (a).¹⁷⁰ This is because pipeline operators are, with one or two exceptions, not vertically integrated and so do not have an incentive to deny access or behave in a way that adversely affects competition in an upstream or downstream market. To the contrary, they generally have an incentive to encourage access to maximise profits and reduce the risk of asset stranding. While pipeline operators may not have an incentive to adversely affect competition in another market, they still have an incentive to engage in monopoly pricing and, as highlighted in chapter 6, are acting on that incentive.

¹⁷⁰ In all but two of the applications that have been made for coverage, revocation of coverage and 15-year no-coverage determinations in relation to transmission pipelines in the east coast over the last 18 years, the case for coverage has failed on the basis of criterion (a) not being satisfied. Criterion (a) was found not to be satisfied in these cases because, the dependent markets were found to be workably competitive, the pipeline operator was found to lack the incentive and/or ability to adversely affect competition in these markets and/or there were sequential monopolies. The two exceptions were:

- The MSP—At the time this decision was made AGL had a 30 per cent interest in APA and one of the factors that the Commonwealth Minister pointed to when noting that criterion (a) was likely to be satisfied in this case was the ‘substantial risk of vertical leveraging discrimination in favour of the wholesale and retail markets, given the close relationship between AGL, EAPL and Australian Pipeline Limited.’
- The DVP—The coverage status of this pipeline has changed three times over the last 16 years and while it is currently unregulated, in the past it has been found to satisfy criterion (a) because the owners of this pipeline have interests in upstream production and were found to have an incentive to leverage its market power from transmission into the upstream market.

Further detail on these decisions can be found in appendix 4.

See Commonwealth Minister for Industry, Tourism and Resources, *Applications for Coverage of Certain Portions of the Moomba to Sydney Gas Pipeline System Decision*, 19 November 2003, Commonwealth Minister for Industry, Tourism and Resources, *Application for Coverage of the Dawson Valley Pipeline Decision*, 26 April 2006, p. 6.

See also NCC Past Applications Register http://ncc.gov.au/applications-past/past_applications for the decisions. A summary of the key decisions can also be found in AEMC, *Stage 1 Final Report: East Coast Wholesale Gas Market and Pipeline Frameworks Review*, 23 July 2015, appendix D.

The hurdle posed by criterion (a) has, in effect, allowed pipeline operators to engage in monopoly pricing in a relatively unconstrained manner. This is operating to the detriment of economic efficiency and consumers more generally because monopoly pricing can give rise to lower than efficient levels of gas production and exploration investment, lower than efficient levels of gas use and investment in downstream markets, inefficient utilisation of pipelines and distortions in gas flows across the market.

The emphasis that criterion (a) places on competition in dependent markets is arguably at odds with the NGO. As noted in the Second Reading Speech, the NGL has economic efficiency and the long-term interests of consumers of gas as its central focus¹⁷¹:

“The long-term interest of consumers of gas requires the economic welfare of consumers, over the long-term, to be maximised. If gas markets and access to pipeline services are efficient in an economic sense, the long-term economic interests of consumers in respect of price, quality, reliability, safety and security of natural gas services will be maximised.”

In its 2013 Inquiry into the National Access Regime, the Productivity Commission noted that criterion (a) had been framed in this way because competition is viewed as a proxy for the efficiency gains associated with access, and the gains must be material enough to counter the direct and indirect costs of regulation.¹⁷² However, the problem with using competition as a proxy for efficiency is that competition and efficiency are not synonymous. That is, while competition may promote efficiency, significant efficiency improvements can still be achieved in upstream and downstream markets, without any change in competition in a related market, if a pipeline’s market power is constrained. For example:

- The elimination of monopoly pricing on a pipeline that is used by two retailers to supply gas to a regional area may not give rise to any change in competition in the retail market (for example, because the scale of the market may be too small to attract any other competitors) but could still benefit consumers in the region if the cost savings are passed on.
- Restricting a pipeline operator’s ability to effect a wealth transfer from producers can also be expected to result in efficiency improvements in the upstream market, but may not have any effect on the level of competition in this market if it results in existing producers carrying out more exploration and supplying more gas into the market. In this example, there would be an efficiency improvement and an improvement in consumer welfare but no change to the level of competition.¹⁷³
- Eliminating monopoly pricing on a pipeline that is used to supply a mining company competing in a global commodities market that is already workably competitive could result in greater investment by the mining company (that is, because the risk of hold up is reduced) and increase the volume of commodities it supplies into the market. If the mining company is a lower cost operator, then the increase in supply would displace higher cost suppliers and the equilibrium commodity price would fall. In this example, restricting a pipeline operator’s ability to engage in monopoly pricing would result in an improvement in economic efficiency and consumer welfare but would have little to no effect on competition if the market is already workably competitive.
- In a similar manner to the previous example, restricting a pipeline operator’s ability to engage in monopoly pricing on a pipeline that is used to supply an industrial customer that competes in a workably competitive market in Australia could result in greater investment by that company in its facility and greater output. While this may not give rise to any change in the level of competition in the market, there would still be an efficiency improvement and if the industrial customer is a lower cost producer, it could also result in a reduction in prices for that product, which would benefit consumers.

171 South Australian Hansard 2008, National Gas (South Australia) Bill 2008, Legislative Assembly, 9 April 2008, p. 2701.

172 Productivity Commission, *Final Report—National Access Regime*, 25 October 2013, p.2.

Similar comments were also made in the Harper Review. See Harper Review, *Final Report—Competition Policy Review*, March 2015, p. 73.

173 NCC, *Final Recommendation—Application for coverage of the South Eastern Pipeline System*, 8 April 2013, p. 29.

In all of these cases, constraining the pipeline operator's exercise of market power would be consistent with the efficiency principles embodied in the NGO and would be in the long-term interests of consumers, even though it has no effect on competition in another market. Under the coverage criteria, however, this behaviour would not be sufficient to trigger regulation even if the gains from the efficiency improvements exceeded the costs of regulation.

The problems with relying on competition as a proxy for efficiency were acknowledged by the Productivity Commission in its 2013 Inquiry as highlighted in the following extract¹⁷⁴:

"...competition can be an imprecise proxy for efficiency in some circumstances, particularly with regard to monopoly pricing. This may be the case where monopoly pricing by an infrastructure service provider does not affect the level of competition in dependent markets."

While the Productivity Commission considered changing criterion (a) to an efficiency test, it concluded that such a test would be 'unworkable'¹⁷⁵ and that tools other than Part IIIA may be required where an exercise of market power has no effect on competition in a dependent market^{176, 177}:

"Where competition is not disrupted but monopoly pricing exists, it may be the case that a different form of intervention is justified. For example, some industries (such as airports) are subject to prices surveillance under Part VIIA of the CCA and declaration could supersede the use of these less intrusive approaches ... Monopoly pricing may also be addressed through pricing regulation under industryspecific access regimes (such as is the case for electricity networks)."

The market failure described by the Productivity Commission in this context is the same one that the Inquiry has found. That is, pipeline operators are using their market power to engage in monopoly pricing at the expense of consumers and economic efficiency (contrary to the NGO), but the exercise of this market power appears to be having little to no effect on competition in dependent markets. Rather than allowing this market failure to persist, there is a case for replacing the coverage criteria in the NGL with a new test that addresses the market failure more directly and ensures that the NGO and policy makers' original intentions (that is, preventing the 'abuse of monopoly power' and providing for access on fair and reasonable terms) are met.

Similar views were also reached by independent economic consultants, Incenta and Castalia, in separate reports prepared for the AEMC on the appropriateness of the coverage criteria as a test for regulation under the NGL. The following extracts taken from the Incenta report highlight what it sees as the main shortcoming of the coverage criteria and how it should be addressed:

*"Rather than a problem of the denial of access, the issue with respect to gas pipelines is one of monopoly pricing. It is our view that criterion (a) is not centrally focused on this question, which in turn raises a prospect that price regulation may not be applied when it is justified."*¹⁷⁸

174 Productivity Commission, *Final Report—National Access Regime*, 25 October 2013, p. 173.

175 *ibid*, pp.172–3.

176 Productivity Commission, *Final Report—National Access Regime*, 25 October 2013, p.173 and Productivity Commission, *Draft Report—National Access Regime*, May 2013, p. 178.

177 The view expressed by the Productivity Commission in this context is consistent with its view that the only market failure that Part IIIA should be used to address is:

"...an enduring lack of effective competition, due to natural monopoly, in markets for infrastructure services where access is required for third parties to compete effectively in dependent markets."

The NCC made a similar observation in its recommendation on the application for declaration of the Port of Newcastle. In this case the NCC noted that:

"Declaration under the National Access Regime is not a mechanism for imposition of price regulation and was never intended to be such. 'Excessive', 'monopolistic' or 'gouging' pricing per se is not the focus of Part IIIA. Where such pricing in one market merely transfers income or value from one party in a supply chain to another without materially impacting competition in any other market, Part IIIA does not provide a remedy. The focus of the Regime is on promotion of competition in markets where the lack or restriction of access to infrastructure services provided by facilities that cannot be economically duplicated would otherwise limit competition."

See Productivity Commission, *National Access Regime Final Report*, 25 October 2013, p. 5 and NCC, *Final recommendation: Declaration of the shipping channel service at the Port of Newcastle*, 2 November 2015, pp. 13–4.

178 Incenta, *Assessment of the coverage criteria for the gas pipeline access regime*, September 2015, p. 24.

“On the basis that we consider that the regime under Part IIIA is focused on addressing a different economic problem to the one that emerges from substantial market power held by gas pipelines, it follows that we do not think there is a pressing need for the continued alignment between this regime and the one for gas access coverage. As demonstrated by the Hilmer Review, the national access regime was never intended to provide a regime for price regulation in instances of market power. By continuing to apply a form of test focused on providing regulated access to a circumstance where regulation should focus more on price, there is an increased risk that regulation is not applied in circumstances where it would otherwise be justified.”¹⁷⁹

“It is our view that the potential risks of under or over-regulation that arise under the current regime for gas coverage can be addressed by asking a more straightforward question, namely: do the costs of regulation outweigh its benefits. In this case, this question can largely be answered by asking whether a gas pipeline owner possesses, and is able to apply, substantial and enduring market power.”¹⁸⁰

Castalia formed a similar view, although it suggested that the test for regulation could just be amended by replacing the term ‘competition’ in criterion (a) with the term ‘efficiency’ and restoring the focus of criterion (b) to a natural monopoly test.¹⁸¹

Breaking the nexus between the gas access regime and Part IIIA

While some market participants may raise concerns about the proposal to break the nexus between the gas access regime and Part IIIA, it is clear from the preceding discussion that Part IIIA is not designed to address monopoly pricing that has little to no effect on competition and that an alternative test is required under the NGL.

Further support for this view can be found in the Report by the Independent Committee of Inquiry on National Competition Policy (the Hilmer Committee), which drew a clear distinction between the regulatory measures to be employed when dealing with a natural monopoly that has vertical interests (that is, access regulation) and one that does not (that is, price based regulation).¹⁸² This distinction can be seen in the following extracts:

“Where the owner of the ‘essential facility’ is not competing in upstream or downstream markets, the owner of the facility will usually have little incentive to deny access, for maximising competition in vertically related markets maximises its own profits. Like other monopolists, however, the owner of the facility is able to use its monopoly position to charge higher prices and derive monopoly profits at the expense of consumers and economic efficiency. In these circumstances, the question of ‘access pricing’ is substantially similar to other monopoly pricing issues, and may be subject, where appropriate, to the prices monitoring or surveillance process outlined in chapter 12.

..

“Where the owner of the ‘essential facility’ is vertically-integrated with potentially competitive activities in upstream or downstream markets...the potential to charge monopoly prices may be combined with an incentive to inhibit competitors’ access to the facility.”¹⁸³

¹⁷⁹ Incenta, *Assessment of the coverage criteria for the gas pipeline access regime*, September 2015, p. 30.

¹⁸⁰ *ibid.*

¹⁸¹ Castalia, *AEMC Gas Access Regime Advice*, 10 August 2015, p. 16.

¹⁸² The Inquiry recognises that Part IIIA may be capable of being applied in some limited circumstances where the infrastructure owner has no vertical interests, but there is evidence that it is engaging in price discrimination, or other behaviour, that has a material impact on competition in a related market.

See *Sydney Airport Corporation Ltd v Australian Competition Tribunal* [2006] FCAFC 146.

¹⁸³ Report by the Independent Committee of Inquiry on National Competition Policy, Final Report, 1993, pp. 240-241.

“Where the conditions for workable competition are absent—such as where a firm has a legislated or natural monopoly, or the market is otherwise poorly contestable—firms may be able to charge prices above the efficient level for periods beyond those justified by past investments and risks taken or beyond a time when a competitive response might reasonably be expected. Such ‘monopoly pricing’ is seen as detrimental to consumers and to the community as a whole.”¹⁸⁴

While the Hilmer Committee recommended that monopoly pricing be dealt with through price monitoring or prices surveillance, there are a number of examples of price regulation being applied, in a similar manner to that prescribed in the NGR, where a natural monopoly does not have vertical interests (for example, electricity networks and NBN Co.). Experience with price monitoring in ports and airports has also shown that such monitoring has little or no longer-term impact on the conduct of a natural monopoly, and that at a minimum parties negotiating access to these facilities should be able to have recourse to a dispute resolution mechanism if there is a dispute about the price or terms and conditions of access.

Another way of looking at this issue is to consider what would occur if there were two pipelines competing to supply a location, with no other alternatives (for example, the MSP and the EGP into Sydney), and the pipelines proposed to merge. Most competition authorities would block such a proposal because the loss of competition would be expected to have a detrimental effect on economic outcomes (for example, through higher transportation costs and higher prices for products where gas is a key input) and economic efficiency in upstream and downstream markets (for example, lower than efficient levels of gas production, investment in exploration, gas use and investment in downstream facilities). This economic harm justifies a policy action, which in this case would be to oppose the merger. If there was just one pipeline operating to supply a location (for example, the SWQP or the TGP), then applying the same rationale there would be a case for implementing some form of price regulation to constrain the pipeline operator’s behaviour.¹⁸⁵

Finally, it is worth noting that the link that currently exists between the gas access regime and Part IIIA of the CCA is unique and that a range of other approaches have been used in various industries to impose regulation, including:

- various governments requiring asset owners to submit an access undertaking or an industry specific regime through legislation or other legal instruments¹⁸⁶
- various governments and regulatory bodies deeming certain assets or services to be declared under Part IIIA, or under other industry specific regimes, including the gas access regime when the Gas Code first came into effect¹⁸⁷
- governments adopting an industry specific access regime that provides for an alternative test to determine whether an asset or service should be regulated and/or the form of regulation to be applied.¹⁸⁸

184 Report by the Independent Committee of Inquiry on National Competition Policy, Final Report, 1993, p. 269.

185 In practice there may be different legal standards applied to merger control as opposed to new regulatory controls. Here the Inquiry is merely observing that there is a case for government action to address specific economic outcomes, whether those outcomes arise from merger or from some other route to monopoly.

186 This approach has been used by the Commonwealth government to impose regulation on airports until 2002 and wheat export terminals. It has also been used to require Australian Rail Track Corporation (ARTC) to submit a voluntary access undertaking to the ACCC.

187 This approach was used by state and territory governments to regulate electricity networks and was also used when the Gas Code came into effect. The approach has also been used by the ACCC to impose regulation on a number of telecommunications services and the Commonwealth Government to impose regulation on all NBN services and other high speed broadband services.

188 For example, the ACCC has the power to declare services under Part XIC of the CCA either on its own initiative or in response to a request for access. In deciding whether to declare a service, the ACCC is required to consider whether it will promote the long-term interests of end-users. In doing so, the ACCC is required to have regard to whether it will achieve:

- the objective of promoting competition in markets for listed services
- the objective of any-to-any connectivity in relation to carriage services that involve communication between end-users
- the objective of encouraging the economically efficient use of, and investment in: the infrastructure by which listed services are supplied; and any other infrastructure by which listed services are, or are likely to become, capable of being supplied.

Once a service is declared the ACCC can make an access determination for the service.

Part IV of the CCA is unlikely to provide an effective remedy

Although Part IV of the CCA is often cited as a backstop to access regulation, it is unlikely that the exercise of market power by pipeline operators as observed in this Inquiry would be captured by this part of the CCA. This is because, as noted above, the majority of pipeline operators are not vertically integrated. It would be difficult therefore to demonstrate that the operator of an uncovered pipeline that has engaged in monopoly pricing, has taken advantage of their substantial market power for one of the purposes proscribed under s. 46.¹⁸⁹

Summary

To summarise, the coverage criteria are not designed to address the market failure that has been observed in this Inquiry. If a new test is not implemented then pipeline operators will continue to engage in monopoly pricing in a relatively unconstrained manner. This will, in turn, operate to the detriment of the east coast gas market and economic efficiency in upstream and downstream markets, the costs of which will ultimately be borne by consumers.

While implementing a new test will result in the nexus that currently exists between the test for regulation in the NGL and Part IIIA and the gas access regime being broken, this is consistent with what has occurred in other industry specific regimes. It is also in keeping with the distinction the Hilmer Committee drew between the regulatory measures to employ when dealing with a natural monopoly that has vertical interests (that is, access regulation) and one that does not (that is, price based regulation).

The proposal to break this nexus should not be construed as a more fundamental criticism of Part IIIA. As the ACCC noted in its submission to the National Access Regime, Part IIIA has an important role to play in Australia's regulatory framework in cases where access is required to compete effectively in dependent markets and there is no industry specific regime in place.¹⁹⁰ There is, however, already an industry specific regime in place in gas with a clearly defined objective (that is, to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas). The Inquiry's observations on the coverage criteria and its recommendation on how the test for regulation should be changed are confined to this regime.

The Inquiry's recommendation on how the test for regulation could be changed is set out in section 7.3.2.

7.2.2 Other gaps in the regulatory framework are allowing pipelines subject to full regulation to engage in monopoly pricing

In addition to the more fundamental limitations outlined above, there are a number of features of the regulatory framework, which mean that even if a pipeline is subject to full regulation, it may still be able to exercise market power.

For example, the AER is currently only required by the NGR to approve on an ex ante basis the price of access to the 'reference service(s)' offered by the pipeline. In the NGR, a reference service is simply defined as a service sought by a significant portion of the market. By contrast, the electricity regulatory regime identifies regulated services by an assessment of the contestability of the services.¹⁹¹ The 'reference service' approach used in the NGR has resulted in a number of non-contestable services being excluded from the AER's ex ante review, whereas

¹⁸⁹ This is consistent with the advice that the Major Energy Users has received on the applicability of Part IV of the CCA, which was attached to its July 2015 submission to the Issues Paper.

¹⁹⁰ ACCC, *Productivity Commission Review of the National Access Regime—Submission to Issues Paper*, February 2013.

¹⁹¹ Under the National Electricity Rules, the AER is required to determine the level of regulation to apply to individual services using a service classification framework that, amongst other things, requires consideration to be given to whether the services are contestable (that is, subject to some form of competition or the threat of competition) or non-contestable.

non-contestable services are arguably a primary target for regulation (because there is no competitive constraint on the pipeline operator's provision of those services).¹⁹²

While the threat of arbitration should in principle impose a constraint on the pipeline operator's behaviour when determining the prices of these services, the Inquiry has been informed by market participants that the costs and resources associated with an access dispute, coupled with the uncertainty surrounding the final outcome, can discourage shippers from triggering these provisions. Information asymmetries may also be contributing to this reluctance to trigger these provisions because shippers are unable to determine how much they are being 'overcharged'. One market participant also noted that there is little utility in being able to trigger a dispute in relation to an existing contract, because any access determination would be bound by the pre-existing contractual rights between the parties, which are protected under the NGL. These limitations mean that operators of full regulation pipelines may still be able to engage in monopoly pricing when setting the price of non-reference services, which is what has been observed in this Inquiry.

Another gap in the regulatory framework, outside the DTS in Victoria¹⁹³, stems from the discretion that currently exists under the NGR to exclude expansions of a full regulation pipeline from the definition of the covered pipeline. This has resulted in tranches of capacity on some full regulation pipelines not being subject to regulation. While a decision to exclude expansions must be approved by the AER, there is little guidance in the NGR on the matters the AER is to consider when making such a decision. More problematic, however, is the fact that if the AER allows the investment to be excluded from the covered pipeline, the only remedy that users have if the pipeline operator engages in monopoly pricing is to apply to the NCC for the expansion to be covered. For the reasons set out above, this is unlikely to be successful.¹⁹⁴ Knowledge of these difficulties means that pipeline operators may be able to engage in monopoly pricing on the expanded capacity in a relatively unconstrained manner.

The Inquiry's recommendation on how to address these and other potential gaps in the regulatory framework applying to full regulation pipelines is set out in section 7.3.3.

7.2.3 Information asymmetries can limit a shipper's ability to identify monopoly pricing and negotiate effectively

Another limitation with the current regime is that there is little publicly available information on the costs incurred by pipeline operators in providing services and the relationship between these costs and the prices charged for services. This is in direct contrast to other jurisdictions, such as the US, where financial reporting is seen as critical to enabling shippers to determine whether the charges are 'just and reasonable' and to negotiate effectively with pipeline operators.¹⁹⁵ The information that interstate pipeline operators in the US are required to report to FERC on a quarterly and annual basis includes, amongst other things^{196, 197}:

- the pipeline's balance sheet, income statement and cash flow statement

192 Where a reference service is a substitute for all of the other services provided by the pipeline operator (or there was a chain of substitutability), then it may be possible to rely on just regulating the reference service. The concept here is that regulating the price of the reference service will then constrain the price of other services offered. A similar approach was taken in the NBN Co Special Access Undertaking. However, it appears unsatisfactory to rely on this substitutability under the NGR given the nature of the services provided. A common reference service for transmission pipelines is the provision of firm forward haul capacity. Other services such as backhaul, bidirectional, renomination and as available services may at best be partial substitutes for firm forward haul capacity. In any event, the degree to which these services are potential substitutes for firm forward haul capacity remains untested by regulators due to these services remaining outside of regulation, either due to pipelines being uncovered or due to the service failing to meet the current NGR requirement that a service be sought by a significant portion of the market.

193 The DTS is subject to a Victorian Ministerial Order regulation, which states that all extensions to and expansions of the DTS are to form part of the covered pipeline.

194 Another reason why it would be difficult to demonstrate that the expansion would satisfy the coverage criteria is that the pipelines that are currently subject to full regulation have not actually been found to satisfy the coverage criteria. They were either deemed to be covered when the Gas Code came into effect (the DTS and RBP) or became covered through the competitive tender provisions.

195 FERC, Order No. 710C-C, 16 August 2011, p. 19.

196 FERC, Form No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form.

197 Interstate pipeline operators are also required to report to FERC on the prices and other key terms and conditions struck in GTAs. This information is viewed by FERC as necessary to 'provide shippers with the price transparency they need to make informed decisions, and the ability to monitor transactions for undue discrimination and preference'. FERC, Order No. 637, 9 February 2000, p. 184.

- detailed information on the value of the pipeline’s assets and accumulated depreciation
- detailed information on the revenue received for transportation, storage and other services and volumes transported
- detailed information on the costs incurred in the provision of services, including the cost of any capital works under construction.

In the Second Reading Speech for the NGL, the Hon. Patrick Conlon noted the importance of shippers having access to cost related information, but it appears that little has been done to date to address this information gap¹⁹⁸:

“...customers can only negotiate with service providers when they have adequate information to determine whether or not payments required of them accurately reflect the efficient cost of providing the service. In a competitive market, the efficient cost is revealed as competing providers seek to outbid each other down to the point where they are covering their costs plus a normal profit. Where a business is a natural monopoly this does not occur and it can be difficult for consumers and regulators to access information from natural monopoly service providers.”

Central Petroleum also noted in its submission to the AEMC’s East Coast Gas Market Review that the lack of transparency on the actual costs incurred by pipeline operators, the capital at risk, previous investment returns and the pipeline operator’s cost of capital meant that it was difficult to assess the reasonableness of offers.¹⁹⁹

The Inquiry’s recommendation on how to address this limitation is set out in section 7.3.4.

7.3 The gas access regime should be strengthened to provide a more effective constraint on pipeline operators

The Inquiry has given some thought to how the gas access regime could be strengthened so that it poses a more effective constraint on the behaviour of pipeline operators. In doing so, the Inquiry has been cognisant of the effect that regulation can have on investment, innovation and the other costs and risks that regulation can expose parties to. There are, however, already sufficient safeguards in the NGL and NGR to ameliorate these costs and risks, many of which have been implemented as a result of recommendations by the Parer Review, the Productivity Commission and the Expert Panel on Energy Access Pricing (see box 7.3). The Inquiry is not recommending any changes to these safeguards.

The proposed improvements are instead designed to make the test for regulation under the NGL and other aspects of this industry specific regime fit for purpose, targeted and proportionate to the market failure that has been observed by the Inquiry (that is, monopoly pricing that results in economic inefficiencies) and will promote the NGO. If the proposed improvements are implemented, the Inquiry would expect the prices charged by pipeline operators to move closer towards the efficient cost of supply, which will, in turn, result in:

- lower delivered gas prices for customers that transport their own gas and other end-users of gas if retailers pass the benefits of lower charges through
- more efficient levels of gas production and investment in exploration
- more efficient levels of gas use and investment in downstream facilities that use gas
- more efficient utilisation of the transmission pipelines, less distortions in the flow of gas across the market and gas flowing to where it is valued most highly.

7.3.1 There are always some costs and risks with regulation but these can be ameliorated through existing safeguards in the NGL and NGR

The key risk of regulation is that it can distort investment incentives. If the regulation is too intrusive, socially beneficial investments may not occur. The Inquiry recognises that regulation

¹⁹⁸ South Australian Hansard 2008, National Gas (South Australia) Bill 2008, Legislative Assembly, 9 April 2008, p. 2890.

¹⁹⁹ Central Petroleum, *Submission to the Pipeline Regulation and Capacity Trading Discussion Paper*, 15 February 2016, p. 2.

of gas pipelines can have a number of unintended consequences. It is important to incorporate safeguards in the regulatory regime to minimise the risk of these occurring.

First, regulation has the potential to deter investments in pipelines. Pipelines are long-lived assets. The demand for the use of a pipeline will depend on the volume of gas available at one end of the pipeline and the demand for gas at the other end. At the time investment in a pipeline is sunk, these are uncertain. The expectation that successful projects will be regulated (that is, asymmetric risk truncation) risks making more marginal projects uncommercial.

This risk can be addressed, possibly to a large degree, by the pipeline operator entering into long-term GTAs with shippers. Foundation customers typically 'underpin' investments in new pipelines and major enhancements of existing pipelines. By purchasing capacity on the pipeline, users or producers take some of the risk otherwise borne by the investor. To the extent these contracts fully fund the investment (including compensating the pipeline operator for any associated risk) then regulation of transport charges at the expiry of these contracts may only have a limited effect on investment in gas pipelines.

Second, the potential for new investment to be regulated may cause investors to delay constructing the pipeline until the future prospects of the pipeline become more certain.

Third, regulation may result in the 'front-loading' of transportation charges. The expectation that transportation charges will be regulated will likely result in investors attempting to accelerate the recovery of capital. The consequence is higher charges earlier in the life of the pipeline.²⁰⁰

While regulation can have these effects, there are already a number of safeguards in the NGL and NGR that are designed to counter these effects, including²⁰¹:

- The 15-year no-coverage determination provisions, which allow the developers of greenfields pipelines to seek a regulatory holiday under the NGL before the pipeline is commissioned if they can demonstrate:
 - the development satisfies the definition of a 'greenfields pipeline project' under the NGL, which is currently defined as:
 - a pipeline that is structurally separate from any existing pipeline (whether or not it is to traverse a route different from the route of an existing pipeline)
 - a major extension to an existing pipeline that is not a covered pipeline, or
 - a major extension to a pipeline that is subject to light regulation if it has been granted an exemption by the AER.
 - the proposed pipeline does not satisfy one or more of the coverage criteria.²⁰²
- The protection the NGL accords commercially negotiated contracts, which in effect means that pipeline operators and shippers can continue to enter into mutually beneficial contracts to underwrite investments if it is efficient to do so.
- The lighter handed form of regulation that can be applied if certain conditions are satisfied (see box 7.4).

200 As noted in chapter 6, there is evidence that pipeline operators already try and recover costs over a shorter period of time than the economic life of the assets to reduce their demand related risks.

201 In addition to these provisions, the NGR also includes speculative investment provisions. These provisions allow pipeline operators that are subject to full regulation to carry out more 'speculative' investments that may not pass the relevant expenditure test in the NGR at the time the investment is made but may do so in the future (for example, building in additional capacity that may not be required for some time). Under these provisions, that portion of the investment that doesn't satisfy the expenditure test, and is not recovered through a surcharge or capital contribution will be excluded from the regulatory asset base but can be rolled in at a later time if it does satisfy the test. The provisions also allow for a different rate of return to be applied to this investment to reflect its more speculative nature (rule 84 of the NGR).

202 The decision to limit the scope of the 15-year regulatory holiday in this way was made on the basis of the following recommendation that the Productivity Commission made in its 2003–04 Review of the Gas Access Regime: *"The Commission's recommendation to introduce binding no-coverage rulings would give regulation free periods of at least 15 years to new pipelines that do not satisfy the coverage criteria. Extending the application of regulation free periods to new pipelines that satisfy the coverage criteria could reduce competition in upstream and downstream markets, and possibly distort investment. The case for providing regulation free periods to all new pipelines is weakened further by the Commission's recommendation to have a monitoring option as an alternative to a regulated access arrangement with reference tariffs."*

See Productivity Commission, *Final Report: Review of the Gas Access Regime*, 11 June 2004, p. 430.

- The merits review provisions, which apply to decisions to regulate a pipeline, light regulation determinations and regulatory decisions by the AER.
- The NGO and revenue and pricing principles in the NGL, which the AER is required to take into account when making a regulatory decision and the Australian Competition Tribunal is also required to consider when reviewing such a decision by the AER.

The Inquiry can see the value of these significant safeguards and is not suggesting that any of these safeguards be removed.

7.3.2 There is merit in introducing an alternative test for regulation

As noted in section 7.2.1, the test for regulation currently embodied in the coverage criteria is not posing an effective constraint on the behaviour of pipeline operators, because it is not designed to be triggered by market power that results in monopoly pricing and economic inefficiencies but has little to no effect on competition in upstream or downstream markets.

To address this deficiency, the Inquiry recommends that the coverage criteria be replaced with a new test that would be triggered if the relevant Minister, having regard to the NCC's recommendation, is satisfied that:

- 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 will or is likely to contribute to the achievement of the NGO.

In broad terms, the application of this test would require consideration to be given to:

- The degree of market power the pipeline possesses (that is, as a result of barriers to entry and, where relevant, any other interests the pipeline operator has in the market, or in other markets that give rise to additional market power) and the extent to which this power is likely to be effectively constrained by:
 - competition from an alternative pipeline
 - competition from alternative energy sources
 - the risk of asset stranding
 - any countervailing power held by shippers
 - any other relevant factors (for example, if the GTAs on foot limit the pipeline operator's ability to exercise market power in the short- to medium-term).
- The prospect that the pipeline's market power will dissipate in the medium-term, which will involve an assessment of the likely future investment in pipeline infrastructure and likely future demand for gas transportation services.
- Whether constraining the pipeline's market power will, or is likely to, promote efficient investment, operation and/or the use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

It is important to note that the inclusion of the latter element of this test is not intended to involve a detailed technical assessment of the efficiency benefits associated with regulation. As the Productivity Commission has previously noted, carrying out such an assessment would be analytically complex²⁰³ and would involve a significant number of assumptions. The test is instead intended to involve a *qualitative* assessment of whether coverage will, or is likely, to contribute to the achievement of the NGO, which is how these types of assessments are usually undertaken in Australia in other regulatory contexts.

In contrast to the coverage criteria, this test reflects the characteristics of the market and will provide a more effective constraint on the behaviour of pipeline operators, in turn this will result in efficiency improvements in the gas market and upstream and downstream markets and

203 This point was noted by the Productivity Commission in its 2013 review of the National Access Regime: *"...assessments of efficiency would be analytically complex (potentially requiring consideration of efficiency impacts in multiple dependent markets), difficult to substantiate, and would increase regulatory discretion, potentially resulting in more errors."*
Productivity Commission, *National Access Regime*, 25 October 2013, p.172.

benefit consumers more generally. The test is also targeted and proportionate to the market failure observed in this Inquiry, and is consistent with the principles embodied in the NGL and with policy makers' original intentions when implementing the gas access regime.

It is worth noting in this context that because pre-existing contractual rights are protected under the NGL, the change to the test may have little to no effect on some pipelines in the short- to medium-term if the capacity has been largely contracted. For example, on the SWQP, one of the foundation customer's GTA doesn't expire until 2024 while the other foundation customer's contract expires in 2034.²⁰⁴ The change should, however, impose a constraint on the pipeline operator's behaviour when those contracts come to an end and when entering into any new contracts, including contracts for the sale of as available or interruptible services.

While the Inquiry is satisfied about the need to move to this new test, it has not been possible as part of the Inquiry to consult with market participants on the specific matters that should be considered when applying this test or on how the new test should be implemented. The Inquiry therefore recommends that the COAG Energy Council ask the AEMC to carry out further consultation on these issues and to advise it of the amendments that would need to be made to the NGL and NGR to give effect to this new test. Some of the matters the AEMC will need to consider as part of this process include:

- the factors to be considered by the NCC and Minister when assessing whether the test is satisfied
- who should have the onus to demonstrate the test is satisfied
- how the new test should be implemented when it comes into operation
- how the new test will interact with other elements of the access regime, including the 15-year no-coverage provisions and the full and light regulation framework.

Factors to consider when assessing whether the test is satisfied

As Incenta noted in its report to the AEMC²⁰⁵, the form of regulation factors in s. 16 of the NGL (see box 7.4) provide a good basis for determining whether a pipeline has substantial market power and are broadly consistent with the matters FERC and the NZ Commerce Commission consider. The AEMC may, however, want to consider whether any refinements or additions should be made to these factors.

For example, there may be value in providing further clarity on the degree of competition that would need to be observed for the NCC and Minister to be satisfied that competition acts as an effective constraint on the pipeline operator's market power. This is because competition between two pipelines may not provide an effective constraint on monopoly pricing and because competitive dynamics can change, as highlighted in chapter 6. In the US, FERC has dealt with this issue by adopting a threshold concentration measure below which it applies less scrutiny. There may therefore be merit in the AEMC considering whether a threshold should be adopted and how the potential for pipelines to engage in coordinated conduct should be taken into account.

Who should have the onus to demonstrate the test is satisfied, or not satisfied

Under the current governance framework, the NCC and the Minister must be satisfied that a pipeline meets the coverage criteria. In the US a different approach has been used, with all interstate pipelines presumed to have substantial market power and the onus placed on the pipeline operator to demonstrate it lacks significant market power if it wants to be subject to market-based (unregulated) rates. The benefit of the US approach is that it overcomes some of the information asymmetries that the Minister and NCC would otherwise face when assessing whether or not the pipeline has substantial market power. A similar approach has also recently been used by the Commonwealth government in relation to bulk wheat port terminal facilities, with all port terminal service providers deemed to be subject to full regulation when the new

²⁰⁴ AGL media release, 'AGL secures pipeline deal to link its gas to eastern markets', 13 July 2007 and Origin media release, 'Origin completes gas transportation agreement with Epic', 15 December 2009.

²⁰⁵ Incenta, *Assessment of the coverage criteria for the gas pipeline access regime*, September 2015, p. 2.

regime came into effect and provision made for a lighter handed option if the ACCC or Minister, having regard to certain matters, decides an exemption should be granted.²⁰⁶ There may be value therefore in considering whether this approach could be used in this context and the costs and benefits that would be associated with employing such an approach.

How the new test should be implemented

Pipelines that are regulated at the time the test comes into effect should be assumed to satisfy the new test and to retain their current regulatory status at that time. From an administrative perspective, there would also be value in considering whether any other unregulated pipelines should be deemed to satisfy the test and be subject to full or light regulation from the date the new test takes effect, as was done when the Gas Code was originally implemented.²⁰⁷ If this is not done, then additional time may need to be built into the current decision making process to provide the NCC and relevant Ministers with time to deal with any additional applications that may be made once the new test is implemented.

In a similar manner to the existing regime, provision should be made for the coverage status of a pipeline to change over time in response to changing circumstances. That is, coverage should be capable of being revoked if a pipeline is no longer found to have substantial market power. Conversely, coverage should be capable of being applied if a pipeline that may not have had substantial market power at one point in time is later found to have substantial market power (for example, because any constraints that may have existed in the past are no longer effective).

Interaction of the new test with other elements of the access regime

The 15-year no-coverage provisions in the NGL currently require the NCC and Minister to be satisfied that one or more of the coverage criteria are not met. The AEMC will therefore need to consider whether any new pipeline that satisfies the definition of a greenfields pipeline in the NGL²⁰⁸ should:

- automatically be granted a 15-year no-coverage determination, or
- be required to demonstrate they don't satisfy the market power test.

The benefit of the first option is that it would provide potential developers (for example, Jemena as the developer of the NGP) with greater certainty about their ability to obtain such a ruling and would eliminate any regulatory related risks that may otherwise come from the application of the market power test. It is also unlikely that a greenfields pipeline would have substantial market power in the early years of its life, particularly if it is developed as a result of a process where there has been 'competition for the market'.

The AEMC will also need to consider how the new test will interact with the test that is currently used to determine whether a pipeline should be subject to full or light regulation. At present, the test requires the NCC to consider:

- the likely effectiveness of the alternative forms of regulation
- the effect of the alternative forms of regulation on the costs that may be incurred by an efficient service provider, efficient users and prospective users, and end-users.

In doing so, the NCC is required to have regard to the NGO, the form of regulation factors (see box 7.4) and any other matters it considers relevant. Given the application of the market power test will effectively involve an assessment of some of the same factors²⁰⁹ that are included in the form of regulation factors, it may be appropriate to exclude some of these factors from the test for whether regulation should be full regulation or light regulation.

²⁰⁶ See *Port Terminal Access (Bulk Wheat) Code of Conduct*, cl. 5.

²⁰⁷ This approach has also been used in a number of other industries, including most notably the electricity industry and telecommunications industry where assets or services were deemed to be regulated.

²⁰⁸ The definition of a greenfields pipeline is set out in s. 149 of the NGL, which states that a greenfields pipeline means:

- a project for the construction of a pipeline that is to be structurally separate from any existing pipeline (whether or not it is to traverse a route different from the route of an existing pipeline)
- a major extension to an existing pipeline that is not a covered pipeline
- a major extension to a covered pipeline by means of which light regulation services are provided if that extension is exempted by the AER.

²⁰⁹ In particular, ss. 16(a)-(f) of the NGL.

7.3.3 Other gaps in the regulatory framework should be considered and remedied

As noted in section 7.2.2, there are some gaps in the regulatory framework, which mean that, even if a pipeline is subject to full regulation, it may still be able to engage in monopoly pricing in relation to non-reference services and expansions that do not form part of the covered pipeline. There may of course be other gaps that have not been identified through the Inquiry and that should be addressed, including gaps that are emerging as a result of the changes underway in the market. For example, if the demand for as available, bi-directional and back haul services continues to grow, then there may be value in incorporating some principles into the NGR that set out:

- how the prices of these services should be established
- how the AER is to deal with uncertain demand for such services
- whether the revenue derived from such services should be used to reduce the revenue requirement on forward haul services or in some way rebated to customers.

The Inquiry therefore recommends that the COAG Energy Council ask the AEMC to review Parts 8–12 of the NGR, and to make any amendments that may be required to address the gaps identified by the Inquiry and the more general concern raised during the Inquiry about the ability of pipelines that are subject to full regulation to be able to exercise market to the detriment of consumers and economic efficiency. In carrying out this review, the AEMC should also consider whether any changes can be made to the dispute resolution mechanism in the NGL and NGR to make it more accessible to shippers, so that it provides a more effective constraint on the behaviour of pipeline operators.²¹⁰

Ideally, this review would be carried out at the same time the AEMC conducts its consultation on the form that the new market-power based test will take and how it should be implemented so that all the changes can be implemented as a package.

7.3.4 Providing shippers with better information would enable them to more effectively negotiate with pipeline operators

Another aspect of the gas access regime that should be strengthened is the information disclosure requirements. The Inquiry is aware that the AER already has the power under the NGL to gather financial and operational information from pipelines that are subject to full and light regulation, and that it has imposed similar annual reporting obligations on electricity networks. If a similar obligation was imposed requiring the reporting of information on an individual pipeline basis for each gas transmission pipeline that operates on an open access basis (that is, both regulated and unregulated pipelines)^{211, 212} then shippers would have more information to determine whether or not the prices they are offered on individual pipelines are cost reflective.

The Inquiry therefore recommends that the COAG Energy Council ask the AEMC to explore:

- how the scope of the information disclosure provisions in the NGL should be expanded to allow the AER to obtain and publish information from unregulated pipelines operating on an open access basis
- the type of financial and operational information that pipeline operators should be required to disclose and the frequency with which it should be disclosed, noting that the purpose of this disclosure is to enable shippers to negotiate effectively with pipeline operators and to determine whether proposed prices are cost reflective.

210 The Inquiry is aware that concerns were also raised about the access dispute provisions to the Victorian Gas Market Taskforce that was chaired by former Federal Minister Peter Reith and that the Taskforce recommended that further work be done to ensure that the access dispute framework is operating effectively.

211 The reference to pipelines providing open access is designed to filter out those pipelines that are only used by the owner of the pipeline.

212 For greenfield pipelines, the information reporting should allow sufficient transparency to facilitate shippers negotiating tariffs beyond the regulatory holiday period.

8 Transport capacity and hub services can be further unlocked to increase efficient use

Prospective users of contract carriage pipelines and hub services²¹³ in the east coast gas market can either purchase capacity directly from pipeline operators or from primary capacity holders through a secondary trade. On pipelines and compressors that are contractually congested, secondary capacity trading can give rise to significant improvements in the efficiency with which the pipeline or compressor is utilised and capacity is allocated. It is relevant therefore to consider whether this trade is occurring and if there are any barriers to it occurring.

Evidence gathered through the Inquiry indicates that some secondary capacity trading by primary capacity holders is occurring on most major arterial pipelines, with longer-term trades being the most common form of trade. While shorter-term capacity trades (that is, for a day or week) were less prevalent, they were found to have occurred in Queensland and South Australia with GPGs and industrial users commonly involved. On some pipelines, including key routes between the north and south, participants seeking pipeline services are acquiring secondary capacity directly from pipeline operators through as available and interruptible services, rather than from primary capacity holders.

Through the Inquiry and the AEMC's East Coast Gas Market Review, concerns were raised about primary capacity holders on major pipelines withholding capacity (that is, economic withholding²¹⁴ or refusing to negotiate access). The Inquiry has investigated these concerns but found no evidence that this is occurring. There is, however, evidence that:

- primary capacity holders are not competing with transport service offerings on key routes between Queensland and the southern states and in the Wallumbilla compound for the provision of hub services
- some pipeline operators are charging excessive prices for as available and interruptible transportation services on these routes and for hub services at Wallumbilla.

The Inquiry has also found evidence of some specific secondary capacity related access issues on regional pipelines.

8.1 Alternative transportation options exist on contract carriage pipelines

There are different options available to transport gas on contract carriage pipelines, the suitability of which for a purchaser will depend in part on the firmness (or flexibility) of the service required²¹⁵, along with the price. These options include: purchasing primary or secondary capacity from pipeline operators, purchasing secondary capacity from primary capacity holders, or entering into a swap, put or delivered price contract with another market participant (see box 8.1 for more detail). Pipeline capacity is currently being marketed on pipeline websites²¹⁶ and on the Wallumbilla Gas Supply Hub Exchange²¹⁷, but the Inquiry has found that

213 The term hub services is used here to describe the compression and redirection services that are required to transfer gas between the array of interconnected pipelines in the Wallumbilla compound.

214 Economic withholding is defined here to mean not using or selling capacity when it would be economically beneficial to do so.

215 For example, a retailer servicing residential demand in Sydney may want to enter a firm GTA, whereas a peaking gas fired generator may prefer an interruptible transportation service. Firm GTA's typically require payments for the transportation regardless of use (that is, capacity payments), whereas interruptible services are charged on the basis of gas actually transported.

216 Access to Jemena's capacity trading website is available at <http://jemena.com.au/industry/pipelines/capacity-trading>; as at 4 April 2016, Jemena as the pipeline owner was listing short-term capacity on the EGP and QGP for purchase for a monthly period—no shippers were listing capacity to buy or sell. Access to APA's capacity trading website is available at: <http://capacitytrading.apa.com.au/capacitytrading.aspx>; as at 4 April 2016 APA as the pipeline owner was listing short-term capacity on various pipelines for purchase for weekly periods no shippers were listing capacity to buy or sell.

217 Access to these capacity listings is available at: http://www.gasbb.com.au/Capacity_per_cent20Listing.aspx; as at 4 April 2016, there was no capacity listed. In addition, as discussed at section 8.4, AEMO proposes in 2016 to facilitate the listing of compression services at Wallumbilla for trade.

most capacity sales are occurring bilaterally outside of platforms. This limits the transparency of capacity sale information for both primary and secondary sales.

Box 8.1: Options to transport gas from Wallumbilla to Sydney

A party wishing to transport gas from Wallumbilla to Sydney in February 2016 had the following options:

- Enter into one of the following types of GTAs with APA, as the owner of the SWQP and MSP:
 - a longer-term GTA for spare firm capacity (to the extent it is available) on the SWQP and the MSP
 - a shorter-term GTA for uncontracted firm capacity on the SWQP and MSP, which could be obtained from APA's capacity trading website²¹⁸
 - a GTA that provides an as available or interruptible service on the SWQP and the MSP.
- Negotiate with an existing capacity holder for secondary capacity on the SWQP and MSP, or a delivered gas supply contract to Sydney (that is, commodity plus transportation (see box 8.2)).
- Enter into a gas swap with another shipper. For example, assume Party A has gas at Wallumbilla and demand in Sydney and Party B has gas at the Gippsland Basin and demand in Gladstone. Under a swap, A could send gas to B's demand in Gladstone and B could send gas to A's demand in Sydney.²¹⁹
- Entering into a put arrangement with an existing capacity holder on the SWQP and MSP. For example, assume Party A has gas at Wallumbilla. Party B has spare capacity on the SWQP and MSP and demand in Sydney. If Party A enters into a put arrangement with Party B and exercises its option, then Party B would be required to take Party A's gas at Wallumbilla and put it on the SWQP to Sydney.²²⁰

8.1.1 Pipeline operators sell both primary and secondary capacity

Some pipeline operators publish 'reference tariffs' on their websites which they use as a starting point to negotiate bilaterally on tariffs with shippers. Over the last two years some pipeline operators have begun listing specific shorter-term firm capacity for sale, that is, for a week (APA) or for a month (Jemena) on websites, but there has been limited take-up of these services to date.²²¹ Two pipeline operators do not publish any reference prices for transportation on websites (for short- or long-term capacity), preferring to negotiate bilaterally with shippers.

Pipeline operators also sell 'secondary capacity'. As available and interruptible transportation services are typically sold by pipeline operators as capacity which, as the names suggest, has lower scheduling priority than a firm service. These arrangements are typically entered into for a number of years and often as an add-on to a firm gas transportation service. These services tend to be paid for on a usage basis, occasionally with a relatively small minimum bill, and as such can be characterised as facilitating short-term capacity usage. The prevalence of these services is quite high on some pipelines. In particular, on the SWQP a large number of contracts that provide for interruptible services have been entered into over the last couple of years whereas no secondary sales of capacity by primary capacity holders have occurred. This may reflect rising demand for capacity on this pipeline, which is increasingly being used to transport gas to and from Wallumbilla, although as noted below demand for transport in particular from Wallumbilla may not be as high as it otherwise might be because of pricing.

218 On 4 April 2016, APA was listing capacity to transport gas from Wallumbilla (across the SWQP and MSP) to Sydney for one week for 5 TJ/day at \$2.15/GJ.

219 The Inquiry identified swaps where northern and southern commodity gas has been swapped between parties with apparent counteracting requirements for extra supply to service demand in the south and the north. These arrangements can reduce transportation costs.

220 A and B could agree commercial terms such as B pays A the Sydney STTM price minus a 'put' fee.

221 As at 4 April 2016, some capacity has been traded on the RBP and more recently on the SEA Gas pipeline; the identification of the parties, including the number of parties who have entered into trade is not published; see <http://capacitytrading.apa.com.au/capacitytrading.aspx>.

8.1.2 Secondary sales of capacity by Shippers are common

Once 'shippers' obtain capacity from pipeline operators, the Inquiry has found that there are very few restrictions in the terms of pipeline contracts which prevent them on-selling that capacity.

The Inquiry has found that some selling of secondary capacity does occur and identified approximately 20 capacity trading 'arrangements'²²² that were in place in 2015 across most major pipelines with durations ranging from three months to 20 years but typically between two to five years. Two contracts are very large, long-term trades of firm capacity on the SWQP. On other pipelines the Inquiry identified approximately 100 TJ of daily firm capacity held under secondary trades (and 20 TJ of as available capacity). Some interesting points to note about these trades are that:

- a number have been entered into between large retailers and also producers (including a few sales of as available transportation)
- four longer-term trades were between large energy retailers and industrial customers
- two longer-term trades were between large energy retailers and smaller players in the electricity generation/retail market
- only two longer-term trades were identified between larger energy retailers and small gas retailers—this is not unexpected as many small gas retailers only operate in Victoria, where contracted pipeline capacity is not required
- a number of master 'spot' agreements facilitating short-term capacity trades were identified in Queensland and South Australia.

For all kinds of capacity trades, including under master 'spot' agreements, capacity is often being sold with commodity gas as 'delivered gas'. Delivered gas sales may be viewed as a form of capacity trade (as opposed to just being the sale of gas to a customer) if the gas is sold with rights for the user to trade this gas in a downstream market (see box 8.2), that is, the buyer receives the capacity which it can then nominate into the downstream market at a daily price it chooses.²²³

222 This is an approximate number based on evidence from larger shippers on major pipelines, which does not therefore account for all likely trades—however, importantly it establishes trade is occurring. Furthermore, for one shipper there were arrangements to facilitate trade with multiple buyers in place but the exact number of buyers was not quantified and so was counted as one arrangement.

223 Under Part 20 of the National Gas Rules, the submission of an offer to the STTMs must be supported by pipeline capacity and trading rights. For example, a party wishing to send gas to the Sydney STTM via the Moomba Sydney Pipeline (MSP) must have trading rights on the MSP backed by rights to capacity. These capacity rights are assigned as part of the delivered gas sale.

Box 8.2: Prevalence and form of secondary shipper trades

- **Capacity trades (transportation only):** This form of trade occurs between the primary capacity holder and the counterparty and entitles the counterparty to utilise the primary capacity holder's capacity (or a portion thereof) and can take a number of forms, including a bare transfer²²⁴, operational transfer²²⁵ or novation.²²⁶ This kind of capacity transfer was observed between retailers, GPGs and LNG projects. All capacity trades with a term of five years or more involved transportation only. Bare transfers were the most common way of acquiring firm transportation capacity over operational transfers and novation with nine long-term bare transfers on foot in 2015. Although APA and Jemena have both introduced web-based platforms to facilitate operational transfers, only two trades have reportedly occurred on APA's platform over that period, which suggests a slow take up of this type of trade.
- **Delivered gas (commodity and transportation):** This form of trade provides for the 'bundled' supply of gas and transportation services by the primary capacity holder to the counterparty. These contracts were most prevalent among retailers and industrial customers, although there are examples of producers entering into these types of trades. There were five examples of trades that provide for the supply of gas to entry points of trading markets. Notably, two industrial customers participating in the STTMs have reported cost reductions from accessing gas markets using these contracts.²²⁷ One large energy retailer noted to the inquiry that it tends to trade delivered gas to smaller gas users because users want gas where they need it.

The Inquiry received evidence that shorter-term capacity is also being traded ex-post on pipelines as a means to reduce either pipeline imbalance payments or STTM market penalties. That is, an industrial user may take more gas (and use more pipeline capacity) than usual on one day, but is able to swap this gas and capacity use with another industrial user with the opposite position ex-post to lower imbalance charges payable to the pipeline operator. This kind of trade is occurring on pipelines generally but also has particular application on pipelines connected to the Adelaide, Brisbane and Sydney STTMs. On STTM connected pipelines imbalance trades allow participants to lower market 'penalties' associated with supplying/consuming more or less gas than scheduled. Data supplied by the AER indicates that these trades are occurring on most days between STTM participants (that is, energy retailers and industrial users).

While short-term trades occur, some market participants noted that the timely coordination of the delivery of gas from the north to the south can be difficult because these types of trade involve multiple assets or asset owners and/or multiple shippers and a delay in communicating with one party might mean a deal is not concluded. A number of market participants provided evidence of ways to overcome search and transaction costs on single routes through agreements commonly referred to as master or master spot agreements. These agreements facilitated quick on-the-day trades. The agreements cover standard or 'boiler plate' terms²²⁸, and allow trades to be done via email or even agreed to over the phone. The outcomes are typically reflected in a short transaction notice setting out key agreed on-the-day terms such as the daily or hourly capacity and price.

224 A bare transfer provides for the temporary transfer of the primary capacity holder's rights to the counterparty, but the primary capacity holder remains responsible for all the other obligations under the contract (for example, submitting nominations).

225 An operational transfer provides for the temporary transfer of both the primary capacity holder's operational rights and obligations to the counterparty.

226 A novation provides for the permanent transfer of the primary capacity holder's operational rights and obligations to the counterparty whereby the assignee must enter into a new GTA with the pipeline operator.

227 See www.aemc.gov.au/—East Coast Gas Market Review—AB Cement Submission to the Stage 1 Discussion Paper (p. 3) and Genos' submission to the Stage 1 Draft Report (p. 3).

228 For example, operational terms and conditions relating to gas specification, warranties, liabilities and indemnities.

8.2 There are issues that may affect the take-up of secondary capacity

In response to some of the concerns that have been raised in the context of the AEMC's East Coast Gas Market Review, the Inquiry examined:

- pipeline utilisation by holders of primary capacity to test whether there is any evidence of economic withholding of capacity
- the pricing of as available and interruptible services by pipeline operators, particularly on the key routes from the south to the north.

8.2.1 Withholding of capacity by shippers is not a problem, except on some regional pipelines

Concerns as to utilisation of, and access to, pipeline capacity were investigated in 2013 by the COAG Energy Council²²⁹, with the assistance of NERA Economic Consulting. In short, NERA found no evidence that would support a conclusion that shippers were withholding capacity for the purpose of achieving a competitive advantage in a related market.²³⁰ In a similar manner to NERA, the Inquiry has found no evidence of economic withholding of capacity by shippers on major arterial pipelines. The Inquiry did, however, identify some issues with regional pipelines, which are discussed in section 8.4.

In relation to the SWQP (and other connected pipelines), one LNG project informed the Inquiry that an area of its strategic focus for gas trading from 2016 was to seek sales opportunities to southern or domestic markets, indicating that until now it had prioritised realising steady state production at its LNG production facilities. This suggests that demand from shippers for transport west and south from Wallumbilla may be materialising now.

Assertions were made to the Inquiry of high priced capacity offers being made on the SWQP by incumbent shippers (or alternatively low-priced offers to purchase gas), however, shippers responded in-turn that they had not received any such requests. The Inquiry considers it most likely that limited requests were made to shippers accounting for the take-up with APA of as available and interruptible contracts on the SWQP. It was apparent shippers had not been actively marketing capacity, however, it was also apparent some were using close to their maximum daily capacity on a number of days.

A potential source of confusion for shippers seeking capacity is that APA currently does not publish eastern and western-haul information (that is, capacity, nominations and actual flow information) separately for the SWQP. This may be leading to some uncertainty in the market because some users may consider there is less or more unutilised capacity than actually exists westwards.²³¹ APA is understood to be progressing changes to publish eastern and western-haul capacity and flow information, which should assist users.

In relation to unutilised capacity on the MSP and EGP, major shippers responded that they acquire capacity to fully cover the highest potential demand for the contracted period. Winter heating demand and GPG appear to be the main drivers of these decisions. For low demand periods outside of winter, there is spare pipeline capacity available, however, this is not actively marketed because there is no demand for it. During the period in question only one major shipper was approached by a party seeking long-term contracted capacity and was able to accommodate this request, whilst others did not report direct approaches.

229 At the time this was carried out, the COAG Energy Council was referred to as the Standing Council on Energy and Resources. Standing Council on Energy and Resources, Regulatory Impact Statement (RIS) Gas Transmission Pipeline Capacity Trading: Decision Paper December 2013 p. 32. This report is available at <https://scer.govspace.gov.au/workstreams/energy-market-reform/gas-market-development/gtpct/>.

230 *ibid*, p. 50.

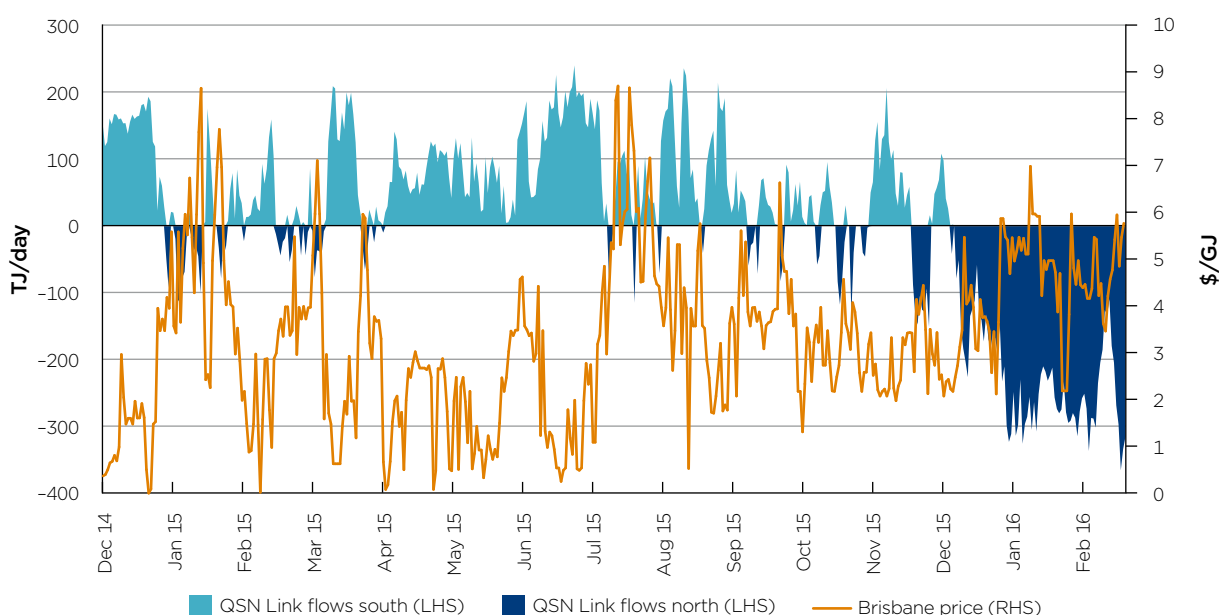
231 See <http://capacitytrading.apa.com.au/capacitytrading.aspx>; as at 4 April 2016, SWQP was reported by APA to be 95 per cent utilised; however, this is understood to be the utilisation of eastward capacity and would not inform users of capacity available in a westerly direction.

Shippers also identified that recent demand drop off on the RBP was leading to potential excess capacity. A number of participants indicated that there was little demand for any spare capacity. In response to concerns raised with the Inquiry, Origin provided an explanation of a \$1.74/GJ offer to sell a small amount of capacity on the RBP, advertised on the Gas Bulletin Board, noting the price reflected the potential opportunity cost of selling capacity which may be required to manage Origin's exposure to electricity pool prices.²³²

8.2.2 Pipeline pricing (including secondary pricing) may affect the efficient utilisation of pipelines

Participants historically have sold some excess gas at Wallumbilla to western and southern markets during the 'ramp gas' phase before LNG train commissioning. However, increasingly southern gas is flowing north to meet the LNG projects' shipping schedules, now LNG plants are operational. This is changing the direction of net flows on the SWQP. Chart 8.1 shows that until December 2015 gas flows were predominantly south from Queensland (positive flows) through the SWQP(QSN) to southern markets, but from December 2015 flows switched to the north (negative flows) reflecting the timing of new LNG plants coming on line at Gladstone.²³³

Chart 8.1: Gas flows from Queensland to New South Wales and Brisbane spot prices



Source: AEMO Gas Market data and Gas Bulletin Board data (www.aemo.com.au, www.gasbb.com.au).

Largely through the influence of LNG demand, the SWQP and other pipelines (such as the MAPS and MSP) are now increasingly accepting gas nominations in both directions and earning 'bi-directional' revenue. The pricing of forward haul versus back haul (both firm and secondary service pricing) is influencing opportunities to bring gas from supply sources to markets and between markets. A number of east coast gas market participants raised concerns to the Inquiry as to the current firm and secondary pricing on a number of routes with bi-directional flows, for example, from Mt Isa to Ballera (on CGP); Wallumbilla to Moomba (on SWQP); Moomba to Sydney (on MSP); and towards Moomba (MAPS).

As noted in section 6.3, the Inquiry found examples of pricing of as available and interruptible services (secondary services) of 185 per cent, 200 per cent and 350 per cent of the firm rates on pipelines forming routes from Wallumbilla. APA has noted to the Inquiry that in structuring its pricing of secondary services including hub services (see section 8.5), it is concerned that tariffs not be lower than the firm service tariff on a comparative \$/GJ usage basis, accounting for actual utilisation by firm service holders. Having reviewed utilisation data, the Inquiry considers

²³² This offer was available at http://www.gasbb.com.au/Capacity_per_cent20Listing.aspx on 18 February 2016. Notably, this price is well in excess of the pipeline operator, APA's published tariffs of \$0.68-\$0.94/GJ.

²³³ GLNG project shipped first gas on 16 October 2015 shipping its 10th cargo in January 2016.

See <http://www.lngworldnews.com/santos-ships-10th-glng-cargo/>
APLNG shipped its first cargo on 11 January 2016, <http://www.aplng.com.au/newsroom/media-releases>.

APA's pricing exceeds in some cases this stated APA pricing basis and, as noted in box 6.2, exceeds a price that might be set by the pricing principles adopted in the EU and US.

It was noted in the previous section that LNG projects with gas to sell domestically may only be beginning to target gas domestic sales now. In March 2016, a deal between QGC (a LNG project operator) to sell gas from fields near Wallumbilla to Incitec Pivot near Mt Isa was announced. Reportedly, Incitec has purchased its own transportation from APA to send the gas west and north on the SWQP and CGP pipelines.²³⁴ Pipeline pricing (including secondary pricing), will be a critical factor in the ability of producers (including LNG projects) to sell gas from Wallumbilla to domestic markets, for example, Mt Isa but also markets further south, for example, Sydney. Importantly, the Inquiry considers secondary pricing to southern markets often extracts more than the price differentials between, for example, short-term commodity prices at Brisbane and markets further downstream. This pricing is likely to limit the utilisation of these pipelines and inhibit the movement of gas to arbitrage prices between the STTMs.²³⁵ Southern route pricing is also likely to impact on whether gas goes to domestic users or international buyers (see box 8.3).

As was also discussed in section 6.4.1, the inquiry considers if pricing on SWQP/MSP was reduced (or pricing reduced through an auction process), more gas would be sold domestically, that is, gas would potentially be diverted to domestic users over LNG spot sales at lower LNG spot prices. In regard to this, the Inquiry has found that firm prices in primary capacity holders' GTAs are not affected by most-favoured nation (MFN) clauses²³⁶, as these provisions would not be triggered by lower as available pricing. That is, any existing MFN clauses do not restrict as available pricing from being reduced to below firm pricing.

The Inquiry notes that there has been a high take-up of secondary contracts with APA on the SWQP (as distinct from utilisation). This may suggest that shippers are not concerned by the prices offered. However, shippers have expressed the opposite to the Inquiry, noting that pricing is influencing their flows on the SWQP or MSP. This suggests that shippers have agreements to transport gas which they are not utilising because the price is too high. At the same time, shippers with primary capacity are unlikely to be able to compete effectively with APA to sell the same services. APA appears better positioned to offer prospective users a mix of services, including the use of different pipeline 'legs', park and loan services and hub compression. APA can also aggregate spare secondary capacity for sale across primary capacity holders. In contrast, shippers on the SWQP may have less certain spare capacity (after peak use), may not be able to sell multiple legs and in any event may be seeking their own arbitrage opportunities.

234 Article at <http://www.northweststar.com.au/story/3829165/incitec-pivot-signs-deal-with-ggc-to-deliver-gas-to-phosphate-hill/>, viewed 4 April 2016.

235 Noting secondary service holders are not required to pay capacity payments and therefore have a stronger choice as services are paid for on a throughput basis.

236 These clauses give the capacity holder a right to receive the same price as in any cheaper equivalent service.

Box 8.3: Transportation costs and arbitrage opportunities between markets

Between domestic markets

Over 2015, there were 300 days where the price for gas in the Sydney STTM exceeded the price for gas in the Brisbane STTM, and 313 days where the price for gas in the Adelaide STTM exceeded the price for gas in the Brisbane STTM. This is categorised by the magnitude of price difference below.

Price difference	Days SYD price > BRI price	Days ADL price > BRI price
Count of $\$0 < x \leq \1	116	84
Count of $\$1 < x \leq \1.50	61	69
Count of $\$1.50 < x \leq \2	47	51
Count of $\$2 < x \leq \3	48	52
Count of $> \$3$	28	57

Taking potential sales from Wallumbilla into Sydney as an example, the Inquiry notes the current pricing of as available services to Sydney via the SWQP and MSP to be in excess of \$3/GJ²³⁷ compared to about \$1/GJ to Brisbane. The STTM price differentials appears to limit any incentives to re-direct short-term gas to the Sydney STTM unless the market price difference is over \$2/GJ (see occurrences and magnitude of pricing differences between regions in the table above).²³⁸ The SWQP is a common route to both the Adelaide and Sydney STTM, however, because MAPS prices are lower than MSP the price difference required to divert gas to the Adelaide STTM is likely to be lower at about \$1.50/GJ.

Between domestic and export markets

The amount of gas nominated for LNG usage, that is, from the Queensland CSG fields was over 2500 TJ/d as at the end of March 2016.²³⁹ This quantity is much larger than Brisbane market demand (under 100TJ/d in 2016).²⁴⁰ It is likely there will be times where the choice for sellers will be between exporting gas, at LNG spot prices, or selling to users other than in Brisbane (which can only support a certain quantity of gas). Southern routes costs (for example, over \$3/GJ to Sydney) will be critical to whether domestic or international users ultimately receive that gas. At lower transport prices, more gas would be diverted to domestic users.

These observation are of relevance to the AEMC proposed reforms relating to the auctioning of capacity (discussed in section 8.3) and in particular the application of that auction to services in different directions on bi-directional pipelines. Lower pricing of transportation by the pipeline operators (or by shippers with capacity to sell) could lead to more gas flowing to southern states.

8.3 Pipeline capacity and gas flows can be further unlocked

Capacity, including secondary capacity/services, is being bought and sold. However, information transparency, search and transaction costs, and also the pricing of transportation are barriers to further capacity utilisation and gas flows.

As shown in Box 8.4, the AEMC East Coast Gas Market Review has proposed a number of reforms designed to encourage the development of a liquid market for the secondary trade of pipeline capacity.

237 By comparison, APA has been listing a firm transportation service via the SWQP (and MSP) to Sydney of 5 TJ for rolling weekly periods via its website at \$2.15/GJ. That is, we understand payable every day regardless of use. For the RBP, APA's published tariff is 68 cents/GJ.

238 The published tariff for transportation on RBP is \$0.68/GJ and as available services are a multiple of that.

239 AER Gas Weeklies, *Roma production*, <http://www.aer.gov.au/wholesale-markets/market-performance>.

240 *ibid.*

Box 8.4: AEMC's draft recommendations on secondary trading²⁴¹

In its Stage 2 Draft Report on the *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, the AEMC recommended the following initiatives to encourage the development of a liquid market for the secondary trade of pipeline capacity trade:

1. A day-ahead auction of contracted but un-nominated pipeline capacity^{242, 243}, which will be conducted shortly after nomination cut-off and be subject to a regulated reserve price that will be determined periodically by the AER. The AEMC noted that the reserve price should enable any incremental costs incurred in the provision of the capacity to be recovered and in certain circumstances could be based on the short run marginal cost. Under the AEMC's proposal, pipeline operators will retain the auction proceeds and be required to publish the auction results.
2. The mandatory creation of a capacity trading platform by each pipeline operator or jointly by pipeline operators, which will be used to:
 - facilitate capacity sales by primary capacity holders ahead of the nomination cut-off time by enabling shippers to anonymously list spare capacity or interests in acquiring capacity
 - publish key information on all secondary capacity trades (for example, price, capacity traded, duration of trade and other terms and conditions that may affect price), irrespective of whether or not the trade occurs via the trading platform.

To facilitate trade through the platform, the AEMC has also recommended that industry develop standardised capacity products.

Together these initiatives are expected to:

- reduce search and transaction costs
- reduce informational gaps and enable more informed decisions to be made about capacity
- enable prospective shippers to access competitively priced secondary capacity on a non-discriminatory basis and for capacity to be allocated to those that value it most
- improve the incentives primary capacity holders have to trade capacity.

Further insight into the AEMC's rationale for these initiatives can be found in the following extract:

"As the only seller of capacity beyond the nomination cut-off time, the pipeline owner has the ability and incentive to price contracted but un-nominated capacity above levels expected in a workably competitive market... high prices for such capacity, in combination with the shippers' limited incentives to trade, may be resulting in inefficient outcomes that the recommended auction might address (at page 55)."

The AEMC went on to add that the auction should provide primary capacity holders with a greater incentive to sell spare capacity prior to the nomination cut-off time because:

- the auction will, in effect, mean primary capacity holders can't block a potential competitor
- revenue from sales prior to the cut-off time will be captured by primary capacity holders rather than the pipeline operator.

While some consideration was given to a long-term 'use it or lose it' mechanism, the AEMC decided not to recommend this option but noted that further consideration may be given to it if the auction results in insufficient levels of trade.

The Inquiry considers there is merit in these proposals. The following findings are noted as particularly relevant to the AEMC's assessment of the costs and benefits associated with these proposals:

- as there is no evidence of economic withholding of capacity on major pipelines (as distinct from regional pipelines), a longer-term 'use it or lose it' type policy may not lead to significant benefits which may nevertheless be addressed by the AEMC's day-ahead auction proposal
- pricing of as available and interruptible services on pipelines linking the north to the south may affect the efficient utilisation of capacity in the long term suggesting potential benefits from the AEMC's day-ahead auction proposal
- the evidence presented of the difficulties in achieving short-term deals to coordinate delivery of gas over multiple pipeline legs from the north to the south suggests benefits from centralising the place where capacity (and commodity) can be traded
- the evidence of short-term trades being facilitated through master agreements between parties with historical arrangements suggests likely benefits from reforms to standardise gas transportation agreement terms irrespective of whether or not the auction proposal proceeds, that is, to lower barriers to entry for new participants.

8.3.1 Search and transaction costs remain high

Search and transaction costs were identified as being high by the COAG Energy Council in 2013, when participants indicated a six month contract term may be required to overcome these costs.²⁴⁴ This is in turn supported by the Inquiry's findings that a typical contract transferring capacity lasts more than a year.

This does not entirely explain, however, why more master agreements have not been struck to date to facilitate the possibility of trades at short notice—the most likely reason is that demand for such agreements has been low. For example, competition in the Adelaide and Sydney retail markets is still emerging with retail market shares still dominated by AGL, Origin and Energy Australia. In particular, there is limited trade through the Adelaide and Sydney STTMs and a continued reliance on long-term contracts.²⁴⁵

The Inquiry considers that the development of standardised GTAs could further assist with reducing search and transaction costs and may be of particular use to new entrants in the market. As described to the Inquiry, with such agreements in place, covering standard terms and conditions, trades can be done very quickly, for example, by email where the daily and/or hourly capacity requirements are expressed and the price agreed and accepted.

241 AEMC, Stage 2 Draft Report, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, 4 December 2015, pp. 51-74.

242 This type of capacity is currently sold by pipeline operators as 'interruptible' or 'as available' capacity.

243 The AEMC noted that if the auction is required on pipelines that have a low proportion of contracted capacity, pipeline operators may not be able to recover their capital costs. The AEMC has therefore noted the potential to exempt pipelines on a case by case basis or to set the auction reserve price above the short run marginal cost on these pipelines. The AEMC also noted there may be little value in requiring an auction on certain single shipper pipelines.

244 NERA, *Analysis of Policy Options to facilitate enhanced gas transmission capacity trading: A report for the Standing Council on Energy and Resources* (November 2013) p. 34.

245 As noted above, however, after-the-day imbalances are being traded at short notice to avoid market deviation penalties.

Ultimately, the ‘fungibility’ of trade of any standardised secondary GTA will in part depend on the degree to which it interacts with ‘bespoke’ primary GTAs and in turn how primary capacity holders are impacted by the terms in the secondary GTA. These issues are being considered within the AEMC processes.²⁴⁶

One participant specifically noted to the Inquiry the difficulties in negotiating capacity for the next day, indicating that small delays may result in a trade not occurring, especially if multiple pipeline legs are required. Other participants noted more broadly the difficulty in coordinating commodity and transportation deals across multiple pipelines.

This indicates that the greatest benefits from a standardised platform for capacity trading and the day-ahead auctioning of capacity are likely to be realised through a platform, which allows participants easily to transact a complete ‘package’ of transportation (and potentially commodity) requirements. The Inquiry recommends the AEMC consider requiring the introduction of a centralised capacity trading platform. Potentially the Wallumbilla GSH operated by AEMO could incorporate this functionality, facilitating shorter-term commodity and capacity trades being available in one centralised place.²⁴⁷

8.3.2 Day-ahead auctioning of capacity may reduce short-term prices and increase gas flows

The Inquiry notes that interruptible and as available prices on some key pipelines joining Queensland and the southern states are currently priced such that they often extract more than the price difference between domestic markets. A potential benefit of the auction proposal may be to lower the price of short-term capacity and facilitate more utilisation and increased gas flows south and between STTMs.²⁴⁸

The auction’s impact will depend on its application, for example, to all pipelines or just ‘fully contracted’ pipelines. The Inquiry understands, for example, that the pipeline industry body, APGA, is considering with its members whether the auction should apply on pipelines that are somewhere between 50 per cent and 100 per cent contracted. Its members are balancing concerns of fostering greater utilisation against concerns the auction may undermine firm investments in pipelines, which it argues supports their long-term sustainability.²⁴⁹ As noted above two critical pipeline routes to southern markets are the SWQP (west) and MSP (south). The inquiry considers that contracts in place across alternate routes on pipelines, e.g., the SWQP east and west are relevant to any ‘investment risk’ and as the SWQP is fully contracted east there is little reason not to apply the auction to the SWQP (west) too.

However, the Inquiry considers in regard to the day-ahead auctioning of capacity that the AEMC should carefully consider the effect that the auction may have on the flexibility that shippers, such as GPGs²⁵⁰, currently have to manage variations in demand as part of a broader costs-benefit assessment of the auction. Evidence to the inquiry has been that GPG are increasingly seeking more interruptible services given the changes underway in the National Electricity Market and that the ability to renominate as part of a contractual right is becoming of increasing importance. The Inquiry understands that the AEMC is considering this issue and other issues raised by participants in regards to the workability of an auction process.

8.3.3 Publishing information on secondary (and primary) capacity trades

The Inquiry has found that secondary trades are occurring along with primary capacity trades. As noted in table 6.1, anti-competitive price discrimination by pipelines appears not to be occurring but shippers may require more information on the costs incurred by pipelines to determine whether or not the prices offered by the pipeline operator are cost reflective and to negotiate more effectively with pipeline operators. The Inquiry’s recommendation in section 7.3.4

246 Submissions to the AEMC Stage 2 Draft Report (December 2015) raised this issue.

247 If this is not suitable given its current focus on the Wallumbilla connected pipelines only, then the Bulletin Board might be another option.

248 It is noted that the current proposal is that the reserve price for the auction will be set at a short-run marginal cost.

249 Australian Domestic Gas Outlook, Steve Davies presentation, Australian Pipeline Gas Association (APGA), 10 March 2016.

250 Submissions to the AEMC Stage 2 Draft Report (December 2015) have specifically raised these issue, for example, Santos, Stanwell public submissions (February 2016) available at www.aemc.gov.au.

to require greater disclosure of this type of information by pipelines should be considered by the COAG Energy Council alongside measures to report secondary and particularly primary capacity trade information. Broadly, all these measures fit into the category of price transparency.

8.4 There are some problems on regional pipelines

In regional areas, users are often supplied by much smaller transmission pipelines, or laterals off major arterial pipelines (jointly referred to here as regional pipelines). The capacity on regional pipelines is often controlled by a single retailer that has contracted all of the capacity, or a significant proportion of the pipeline capacity. Often, due to the size of the capacity held by the incumbent retailer, other retailers are not in a position to offer a firm delivered gas product without acquiring some capacity from the incumbent retailer first. This is a point of difference to major pipelines whereby no single retailer controls all, or has a dominant proportion of total capacity to major cities or industrial hubs such as Mt Isa (CGP) and Gladstone (QGP). Notably, the AEMC's 2014 Retail Competition Review highlighted that retailers may avoid regional pipeline customers where capacity is fully contracted by a small number of retailers and if the size of the customer base is too small to make entry viable given fixed costs.²⁵¹

8.4.1 Limitations on access to capacity and choice of supplier are inhibiting competition in regional areas

The Inquiry heard evidence from some regional gas users that retailers on regional pipelines may have been making it harder for users to obtain or accept commodity gas offers from other retailers, or for other suppliers to make offers, including by:

- not being willing to offer stand-alone transport capacity when sought by a user
- offering prices for stand-alone transport capacity that are much higher than the transport prices implied by the shipper's bundled commodity and transport pricing offers.

This conduct may have had the impact of making alternative commodity offers unavailable, or of making those offers less attractive to users when compared to the shipper's own bundled offers.

The material gathered through the Inquiry also showed that:

- in some cases the only transport capacity offered to industrial users on regional pipelines has been as available capacity, which is not suitable for those users that require firm continuous gas supply
- inconsistent information is sometimes provided by regional pipeline operators and shippers to users, leading to a lack of transparency in regard to unused capacity on regional pipelines.

Under s. 46 of the CCA, a supplier that has a substantial degree of market power in a market must not take advantage of that market power for a proscribed purpose, including the purpose of deterring or preventing another person from engaging in competitive conduct in any market. Under s. 47 of the CCA, a supplier must not engage in exclusive dealing (such as by offering to supply goods or services to a customer, including at a particular price or at a discount, on condition that the customer does not obtain goods or services gas from another supplier), where that conduct has the purpose, or effect or likely effect of substantially lessening competition in a market.

²⁵¹ AEMC, *Final report: 2014 retail competition review*, available at <http://www.aemc.gov.au/Markets-Reviews-Advice/2014-Retail-Competition-Review>. The ACCC has also periodically received inquiries through its Infocentre from users seeking offers on regional pipelines in South Australia and Victoria by consumers who have been told by other retailers they cannot supply them.

The ACCC will consider whether the availability or pricing of capacity on regional pipelines raises any concerns as a possible contravention of the misuse of market power provisions or the exclusive dealing provisions of the CCA. Given the concerns that have been expressed during the Inquiry and the information received about stand-alone transport capacity, the ACCC will be undertaking reviews of specific cases and may take further action. The ACCC's assessment of any particular conduct will depend on the specific nature of the conduct, the circumstances in which it took place, and the characteristics of the market in which the conduct occurred.

8.4.2 New measures would assist regional pipeline users

While the ACCC will be conducting inquiries to determine the extent of issues on regional pipelines, there are a number of other potential policy responses or outcomes the Inquiry considers could assist regional pipeline users:

- Regulation—capital works on regional pipelines have not generally been undertaken to the same extent as on major arterial pipelines (for example, QGP, CGP). Some industrial users seeking to increase production in regional areas have been unable to access capacity and have investigated options to augment regional pipelines. These industrial users have been required to fund the front-end engineering studies to scope augmentation projects and to contribute towards the cost of capital works. Some industrial users have even investigated options to build an entirely new pipeline but have not undertaken these works given excessive costs. Regulation of these pipelines may be a solution because it can offer a stable and equitable path for pipeline charges and greater certainty about the rate of return for augmentations. This could encourage the necessary development of regional pipelines and promote economic growth for local economies surrounding industrial customers seeking to expand operations.
- Capacity surrender—a further mechanism to constrain regional pricing could take the form of a capacity surrender provision which could be invoked, where it is demonstrated that contractual congestion exists²⁵², and that stand-alone transportation is not being made available by a shipper with all or most capacity at competitive prices.²⁵³ The AEMC has previously considered long-term 'use it or lose it' requirements might address substantive capacity withholding issues, however, on regional pipelines the issue is not only one of non-utilisation but also of barriers to a user de-linking from an incumbent retailer.
- Transparency—regional pipeline capacity is not widely advertised and utilisation data is not reported on the Gas Bulletin Board. As such, industrial users are therefore unable to accurately assess how much unused pipeline capacity is available to meet their supply requirements. This creates an asymmetry of information and potentially disadvantages industrial users in negotiations. Reporting of regional pipeline capacity on the Gas Bulletin Board has been identified as a solution by the AEMC.²⁵⁴

8.5 Further improvements in the Wallumbilla GSH could result in more trade

AEMO operates the Wallumbilla GSH, which allows for the wholesale, short term trading of natural gas via an electronic platform in the Queensland Roma region (centred around Wallumbilla). The Wallumbilla GSH is based around the APA-owned Wallumbilla 'Compound', a small area where pipeline intersection has developed over time—beginning with the connection of the RBP to the QGP and then both of these pipelines to the SWQP. More recently, a number of other pipelines, as shown in the illustrative diagram below have connected (see figure 8.1). Over time APA and the previous owners, Epic, have progressively added more compressor stations inside the compound.²⁵⁵

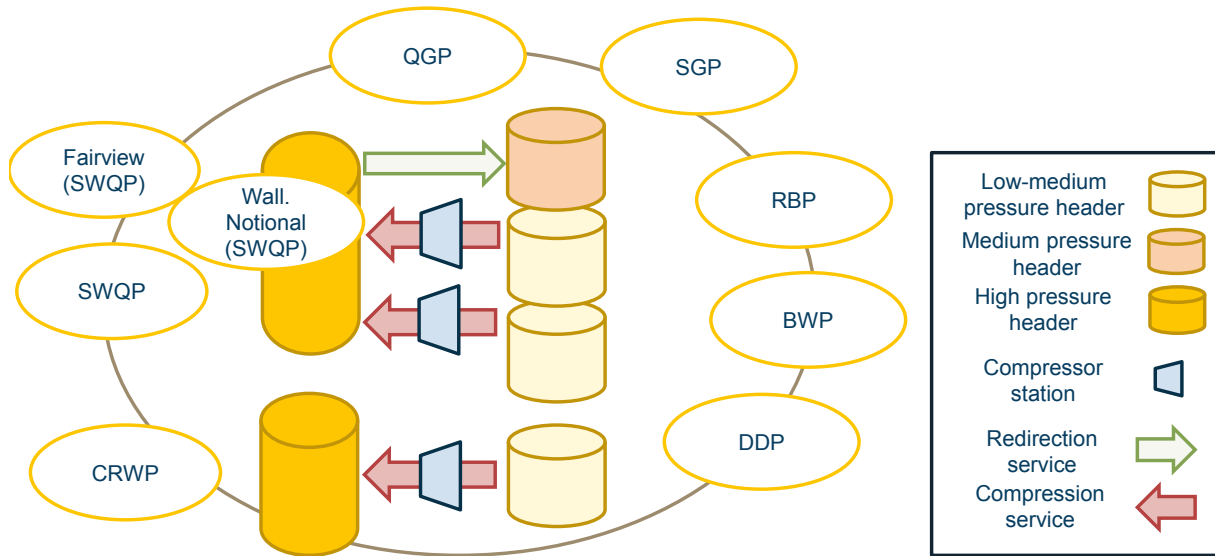
252 Contractual congestion here means that a customer is unable to secure sufficient firm transportation from more than one shipper.

253 Any surrender would relate to the capacity required by the user wishing to leave the retailer, not other capacity.

254 AEMC, *East Coast wholesale gas market and pipeline frameworks review: Stage 2 draft report*, December 2015, pp. 101-2.

255 AEMO, *Hub Services for a Single Wallumbilla Market* (November 2015) p. 3.

Figure 8.1: Diagram of pipelines intersecting with the APA Wallumbilla compound



Source: AEMO, Hub Services for a Single Wallumbilla Market, November 2015, p. 10.

The compressor stations within the Wallumbilla compound are fully contracted to three foundation shippers who have funded their installation over the last few years. APA has provided indicative ranges for interruptible compression pricing up to approximately 18 cents per GJ and redirection pricing of 7 cents per GJ to AEMO for use of these compressors.²⁵⁶ This represents a significant premium (~200 per cent) to the price the Inquiry has found that three foundation shippers are paying under their contracts with APA. While in theory the foundation shippers could compete with APA to sell these services, there is no indication that they are doing so at present.

In an attempt to simplify the execution of gas trades at the hub, AEMO has recently proposed enhancements to the hub 'services' provided at Wallumbilla, which are expected to allow users to move gas into, out of and within the hub more freely and facilitate the creation of one Wallumbilla pricing point (the Optional Hub Services model—see box 8.5). The changes proposed involve a voluntary mechanism for primary capacity holders (that is, the foundation customers with compression in the compound) to trade compression services.

The Inquiry notes that the auction model contemplated by the AEMC (see section 8.3) could be applied to the 'voluntary' optional hub services being implemented by AEMO. The Inquiry considers this is likely to introduce some competitive constraint on the price APA can charge for these services and provide the three primary capacity holders with a greater incentive to trade their capacity. The Inquiry recommends AEMC consider the benefits of a short-term auction process for hub services if it decides to implement the day-ahead auction process for pipeline services.

Industry participants commented that APA and AEMO have been working together to develop the Wallumbilla GSH including any information to support it. For example, APA informed the Inquiry that it is developing further reporting to aid transparency including 'net' flow information on pipelines into and out of the Wallumbilla compound as well as reporting on SWQP flows west and east. Despite awareness of these changes, market participants still maintained concerns as to the overall transparency of services within the hub, in particular, how much compression would be required to deliver gas from one point to another. As the hub develops, the sufficiency of information reporting to allow users to monitor hub services may need to be reviewed. The Inquiry is cautious that FERC in the United States has instigated a number of investigations

²⁵⁶ AEMO, Hub Services for a Single Wallumbilla Market (November 2015) p. 17. APA noted to the Inquiry that the information on interruptible pricing it provided was at the higher end of its interruptible pricing.

around over recovery by pipeline operators of fuel gas for compression. As a result, FERC issued revised guidance to the industry in 2011.²⁵⁷

Box 8.5: Hub services for a single Wallumbilla market

Following on from the introduction of the Wallumbilla Gas Supply Hub in March 2014, the COAG Energy Council asked AEMO to review hub services in 2015 to advise the Council on whether existing hub services (that is, intra-hub gas transfer services such as compression and redirection) are sufficient to support a transition to a single Wallumbilla gas market.

AEMO's November report recommends implementation of a single Wallumbilla product through the Optional Hub Services model but also notes the implementation of the model is compatible with future market development (for example, a Single Trading Zone model).²⁵⁸

The Optional Hub Services Model has been described by AEMO as a low cost model that can be built within the existing Wallumbilla Gas Supply hub exchange framework and includes (voluntary) secondary trading of hub services (compression) through additions to be implemented on the exchange. There will be a default delivery point, however, consideration is being given to participants establishing their own substitute delivery points through bilateral agreements.²⁵⁹

8.6 Energy bodies and participants are working together to facilitate the efficient use of pipeline and hub services

The Inquiry supports the work that the AEMC and AEMO are doing in conjunction with industry and industry bodies to increase the efficient use of pipelines and hub services. It was evident throughout the Inquiry that participants had been very engaged with the AEMC processes, along with the AEMO led Wallumbilla GSH developments. The findings above should assist in the development, and prioritisation, of options around development of hub services, capacity trading platforms, short-term auctions and measures to standardise transportation contracts.

It is apparent that there will need to be some concessions and willingness to adapt. For example, from the pipeline operators if pipeline capacity trading is to be supported alongside commodity trading, and by shippers and pipelines in adapting to any reforms to introduce short-term auctioning of capacity.

²⁵⁷ FERC has conducted a number of investigations into over-recovery of fuel gas especially in the last fifteen years. In 2011 FERC passed a new financial reporting obligation—FERC Order No. 710-C Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines (issued 16 August 2011) see <https://www.ferc.gov/docs-filing/forms/form-2/order710-c.pdf>.

²⁵⁸ *ibid*, AEMO noted in this report that the Single Trading Zone model could involve a mandatory market for hub services where a hub operator is responsible for delivering all transactions and participants pay a standard tariff for a centralised service (under a regulated model). As AEMO notes, a key consideration is whether any further investment is required to achieve the desired level of deliverability for a virtual trading point at Wallumbilla.

²⁵⁹ With the optional hub service model in place the following services will be available at the hub/compound: the transfer of gas from one interconnected pipeline to another, compression services between low and high pressure points, redirection services from one facility to another, gas ownership transfers, short-term storage and balancing services.

Acronyms

ACQ	annual contract quantity
CCA	<i>Competition and Consumer Act 2010</i>
CPI	Consumer Price Index
CSG	coal seam gas
DES	delivered ex-ship
DWGM	Declared Wholesale Gas Market
FID	final investment decision
FOB	free on board
GBJV	Gippsland Basin Joint Venture
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
JCC	Japanese Customs-Cleared Crude
JV	joint venture
LNG	liquefied natural gas
MDQ	maximum daily quantity
MFN	most favoured nation
MPH	Moomba Processing Hub
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
STTM	short term trading market

Organisations

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Stock Exchange
COAG	Council of Australian Governments
EIA	Energy Information Agency (US)
FERC	Federal Energy Regulatory Commission (US)
NCC	National Competition Council
NOPTA	National Offshore Petroleum Titles Administrator

RLMS	Resource and Land Management Services
SEC	Securities and Exchange Commission (US)
SPE-PRMS	Society of Petroleum Engineers-Petroleum Resources Management System

Pipelines

BWP	Berwyndale to Wallumbilla Pipeline
CGP	Carpentaria Gas Pipeline
CRP	Central Ranges Pipeline
CRWPL	Comet Ridge to Wallumbilla Pipeline Loop
CWP	Central West Pipeline
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
QSN Link	Queensland to South Australia/New South Wales Link
RBP	Roma to Brisbane Pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline

Glossary

Conventional gas/Unconventional gas: Conventional gas may be characterised as natural gas contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers natural gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the three major types of unconventional gas as:

- shale gas: natural gas contained within a commonly occurring rock classified as shale
- coal seam gas (CSG): natural gas contained in coalbeds
- tight gas: natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require a large number of wells to be drilled (in the thousands for the large CSG LNG projects in Queensland) over its life to ensure consistent production.

Delivered ex-ship price: The price of gas delivered by ship to a destination port. This term is typically used for LNG prices.

Free on-board price: The price of gas loaded on a ship at a port connected to an LNG plant.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG netback price: A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Sydney is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting natural gas from Sydney to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

Legacy GSA: Gas supply agreements executed prior to 2010 that are still in effect and that have not been subject to a price review.

Pipeline transportation services

As available transportation service: A service that allows the transportation of gas on an 'as available' basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

Firm transportation service: A service that allows the transportation of gas on a 'firm' basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

Interruptible transportation service: A service that allows the transportation of gas on an 'interruptible' basis. The pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and as available transportation services.

Reserves and resources

Reserves: Quantities of natural gas expected to be commercially recoverable from a given date under defined conditions.

1P (proved) reserves: Commercially recoverable reserves with at least a 90 per cent probability that the quantities recovered will equal or exceed the estimated amount.

2P (proved and probable) reserves: Commercially recoverable reserves with at least a 50 per cent probability that the quantities recovered will equal or exceed the estimated amount.

3P (proved and probable and possible) reserves: Commercially recoverable reserves with at least a 10 per cent probability that the quantities recovered will equal or exceed the estimated amount.

Contingent resources: Contingent resources are quantities of natural gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

Prospective resources: Prospective resources are estimated quantities associated with undiscovered natural gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated and an estimate made of quantities that would be recoverable under appropriate development projects.

Units of Energy

Joule—a unit of energy in the International System of Units

Gigajoule (GJ)—a billion (10⁹) joules

Terajoule (TJ)—a trillion (10¹²) joules

Petajoule (PJ)—a quadrillion (10¹⁵) joules

Million British Thermal Units (MMBTU)—1 MMBTU = 1.055 GJ

Appendix 1: Recent inquiries and reports

Queensland Gas Market Review (2012)	Queensland Government	www.dews.qld.gov.au/_data/assets/pdf_file/0006/77775/gas-market-review-2012.pdf
Gas Market Taskforce Report (Reith Report 2013)	Victorian Government	www.energyandresources.vic.gov.au/about-us/publications/Gas-Market-Taskforce-report
Eastern Australian Domestic Gas Market Study (2014)	Australian Government Department of Industry and Science	www.industry.gov.au/Energy/EnergyMarkets/Documents/EasternAustralianDomesticGasMarketStudy.pdf
Examining Barriers to More Efficient Gas Markets (2015)	Australian Government Productivity Commission	www.pc.gov.au/research/completed/gas-markets
Supply and cost of gas and liquid fuels in NSW (2015)	NSW Legislative Council Select Committee	www.parliament.nsw.gov.au/gasinquiry
Gas Market Report (2015)	Australian Government Department of Industry, Innovation and Science	www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Gas-market-report.aspx
Gas Price Trends Review (2016)	Oakley Greenwood Commissioned by the Australian Government Department of Industry, Innovation and Science	www.industry.gov.au/Energy/Energy-information/Pages/Gas-Price-Trends-Review.aspx
East Coast Wholesale Gas Market and Pipeline Frameworks Review (2015–16) (ongoing)	Australian Energy Markets Commission	www.aemc.gov.au/Markets-Reviews-Advice/East-Coast-Wholesale-Gas-Market-and-Pipeline-Frame

Appendix 2: The Inquiry's terms of reference



Minister for Small Business

Mr Rod Sims
Chairman
Australian Competition and Consumer Commission
GPO Box 3131
CANBERRA ACT 2601

09 APR 2015

Dear ~~Mr Sims~~ ^{Rod},

I am writing to require the Australian Competition and Consumer Commission (ACCC) to hold a public inquiry into the competitiveness of wholesale gas prices and the structure of the upstream, processing, transportation, storage and marketing segments of the gas industry pursuant to subsection 9511(1) of the *Competition and Consumer Act 2010* (CCA).

I enclose a notice under subsection 9511(1) of the CCA identifying the matters the inquiry is to consider and when the inquiry is to be completed.

Given that policy responsibility for the wholesale gas industry resides with the Minister for Industry and Science, I ask that the ACCC liaise closely with the Minister's Department. The ACCC may wish to liaise with the Productivity Commission which has recently completed a self-initiated research project examining barriers to more efficient gas markets.

The final report is required to be submitted to the Government within 12 months of the receipt of the attached notice.

I have copied this letter to the Minister for Industry and Science.

Yours sincerely


BRUCE BILSON

Enc.

Parliament House CANBERRA ACT 2600
Telephone: 02 6277 7930 Facsimile: 02 6273 0434
Email: sbminister@treasury.gov.au



COMMONWEALTH OF AUSTRALIA

COMPETITION AND CONSUMER ACT 2010

INQUIRY INTO COMPETITIVENESS OF THE WHOLESALE GAS INDUSTRY

I, Bruce Billson, Minister for Small Business, pursuant to subsection 95H(1) of the *Competition and Consumer Act 2010*, hereby require the Australian Competition and Consumer Commission to hold an inquiry into the competitiveness of wholesale gas prices and the structure of the upstream, processing, transportation, storage and marketing segments of the gas industry. The inquiry may include but not be limited to Victoria, New South Wales, Australian Capital Territory, South Australia, Queensland and Tasmania.

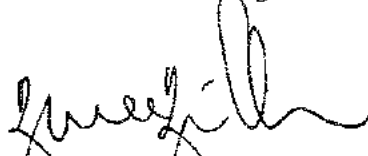
Matters to be taken into consideration in the inquiry shall include, but not be restricted to:

- the availability and competitiveness of offers to supply gas and the competitiveness and transparency of gas prices;
- the competitiveness of, access to, and any restrictions on market structures for gas production, gas processing and gas transportation;
- the significance of barriers to entry into the upstream production sector;
- the existence of, or potential for, anti-competitive behaviour and the impact of such behaviour on purchasers of gas; and
- transaction costs, information transparency including gas supply contractual terms and conditions, and other factors influencing the competitiveness of the markets.

This is not to be an inquiry in relation to supply by any particular person or persons. The inquiry should not consider competition in gas retail markets.

The inquiry is to be completed and a report submitted to me within 12 months of the receipt of this notice.

DATED THIS 8th DAY OF April 2015


BRUCE BILLSON
Minister for Small Business

Appendix 3: Public submissions to the Inquiry

Adelaide Brighton Cement

AGL

Alinta Energy

APA Group

Australian Aluminium Council

Australian Petroleum Production and Exploration Association

Australian Pipelines and Gas Association

Australia Pacific LNG

Argus Media

Arrow Energy

Beach Energy

BHP Billiton

Blue Energy

Business Council of Australia

Cooper Energy

CSR

Energy and Management Services

Energy Networks Association

Energy Supply Association of Australia

Esso Australia Resources

GDF Suez

Hydro Tasmania

Incitec Pivot

Innovative Energy Consulting

Jemena

Major Energy Users Inc

Manufacturing Australia

Origin Energy

Pangaea Resources

Qenos

QGC

Reserve Our Gas Alliance

Santos

Shell Australia

Stanwell

Strike Energy

Appendix 4: The regulatory status of transmission pipelines

Table A4.1: The regulatory status of transmission pipelines and how it has changed since the gas access regime was introduced in 1997

State	Pipeline	Owner	Regulatory status in 1997	What has happened since 1997	Regulatory Status	Current status
NSW	Moomba to Sydney Pipeline	APA	Deemed to be covered when the Gas Code commenced	In 2003 the Commonwealth Minister for Industry, Tourism and Resources decided to revoke coverage between Moomba and Marsden because criterion (b) was found not to be satisfied on this part of the pipeline. The remainder of the pipeline was found to satisfy all of the coverage criteria, including criterion (a) so remained covered. At the time this decision was made AGL had a 30 per cent interest in APA and one of the factors that the Commonwealth Minister pointed to when noting that criterion (a) was likely to be satisfied in this case was the 'substantial risk of vertical leveraging discrimination in favour of the wholesale and retail markets, given the close relationship between AGL, EAPL and Australian Pipeline Limited.'		Unregulated: Moomba to Marsden Light regulation: Remainder
	Central Ranges Pipeline	APA	Built after the Gas Code commenced	Following an application by APA, the NCC decided in 2008 that the covered portion of the pipeline should be subject to light regulation.		Full regulation
	Central West Pipeline	APA	Deemed to be covered when the Gas Code commenced	Following an application by APA, the NCC decided in 2010 that the CWP should be subject to light regulation.		Light regulation
	Eastern Gas Pipeline	Jemena	Built after the Gas Code commenced	In 2000 AGL submitted a coverage application to the NCC. While the NCC and the Commonwealth Minister for Industry, Science and Resources found that the EGP satisfied all the coverage criteria, on appeal the Australian Competition Tribunal found that criterion (a) was not satisfied and concluded that the pipeline should not be covered.		Unregulated

State	Pipeline	Owner	Regulatory Status		
			Regulatory status in 1997	What has happened since 1997	
SA	Moomba to Adelaide Pipeline System	Epic	Deemed to be covered when the Gas Code commenced	In 2007 the South Australian Minister for Energy decided to revoke coverage because criteria (a) and (d) were found not to be satisfied.	Unregulated
	SEA Gas Pipeline SESA Pipeline	Rest/APA APA	Built after the Gas Code commenced	No-coverage application has been made for these pipelines.	Unregulated
	Riverland Pipeline	AGN	Deemed to be covered when the Gas Code commenced	In 2001 the South Australian Minister for Minerals and Energy decided to revoke coverage because criteria (a) and (d) were found not to be satisfied.	Unregulated
	South East Pipeline Systems	Epic	Deemed to be covered when the Gas Code commenced	In 2000 the South Australian Minister for Minerals and Energy decided to revoke coverage because criteria (a) and (d) were found not to be satisfied. In 2012 KCA submitted a coverage application to the NCC, but both the NCC and South Australian Minister for Mineral Resources and Energy found that criteria (a) and (d) were not satisfied, so the coverage status was not changed.	Unregulated
Tas	Tasmanian Gas Pipeline	Palisades	Built after the Gas Code commenced	No-coverage application has been made for this pipeline.	Unregulated
Vic	Declared Transmission System	APA	Deemed to be covered when the Gas Code commenced	No revocation of coverage application has been made for this pipeline.	Full regulation
	Vic-NSW Interconnect Carisbrook to Horsham Pipeline	APA GPV	Built after the Gas Code commenced	No-coverage applications have been made for these pipelines.	Unregulated
Qld	South Gippsland Pipeline	Multinet			
	Roma to Brisbane Pipeline	APA	Deemed to be covered when the Gas Code commenced	No revocation of coverage application has been made for this pipeline.	Full regulation
	Carpentaria Gas Pipeline	APA	Built after the Gas Code commenced	This pipeline originally became covered through Queensland Government legislation but was subject to a derogation, which precluded the ACCC (later the AER) from reviewing the reference tariff until May 2023. In the transition to the NGL and NGR in 2008, the Queensland Government decided to change the form of regulation to light regulation and prohibit changes to the regulatory status until May 2023. This change was made through National Gas (Queensland) Regulation 2008.	Light regulation

State	Pipeline	Owner	Regulatory Status	Current status	
Qld	South West Qld Pipeline	APA	Regulatory status in 1997 Deemed to be covered but subject to a Queensland Government derogation, which precluded the ACCC (later the AER) from reviewing reference tariffs until 2016	What has happened since 1997 In the transition to the NGL and NGR in 2008, the Queensland Government revoked coverage through a regulation, rather than through a formal assessment of whether the pipeline satisfied the coverage criteria. This change was made through National Gas (Queensland) Regulation 2008.	Unregulated
	Queensland Gas Pipeline	Jemena			
	QSN Link	APA			
	Berwyndale to Wallumbilla Pipeline	APA			
	Wallumbilla to Darling Downs Pipeline	Origin	Built after the Gas Code commenced	No-coverage applications have been made for these pipelines.	Unregulated
	North Queensland Gas Pipeline	Vic Funds Mgt Corp.			
	Dawson Valley Pipeline	Meridian JV (Westside and Mitsui)	Deemed to be covered when the Gas Code commenced	The coverage status of this pipeline has changed four times since the gas access regime came into effect: <ul style="list-style-type: none"> When the Gas Code was introduced the DVP was deemed a covered pipeline. In mid-2000 coverage was revoked by the Commonwealth Minister for Industry, Science and Resources because criterion (a) was found not to be satisfied. In this case the Minister noted that because there was only one user of the pipeline with a long-term GSA and no indication of any other producer seeking access or interconnection to the pipeline, access was unlikely to promote competition in any other market. In 2006 coverage was reinstated by the Commonwealth Minister for Industry, Tourism and Resources because all the coverage criteria were found to be satisfied. In this case, the Minister found that because the owner of the pipeline had vertical interests in gas production, it would have 'the ability and incentive to leverage its transmission market power into the upstream market in the absence of coverage'. It was on this basis that the Minister concluded that access would promote a material increase in competition in the upstream market because it would constrain the pipeline operator's ability to charge monopoly prices for transportation services. In 2014 coverage was revoked by the Commonwealth Minister for Industry because criterion (a) and (b) were found not to be satisfied. Criterion (a) was found not to be satisfied at this time because the owners had entered into a 20-year GSA with GLNG, which meant that there was unlikely to be any spare capacity available for third party use from 2015. 	Unregulated

State	Pipeline	Owner	Regulatory Status		Current status
			Regulatory status in 1997	What has happened since 1997	
Qld	Wallumbilla to Gladstone Pipeline	APA		15-year no-coverage determination granted by Commonwealth Minister for Resources and Energy in 2010 because criteria (a) and (d) were found not to be satisfied.	
	APLNG Pipeline	APLNG		15-year no-coverage determination granted by Commonwealth Minister for Energy and Resources in 2012 because criteria (a), (b) and (d) were found not to be satisfied.	
	GLNG Pipeline	GLNG	Built after the Gas Code commenced	15-year no-coverage determination granted by Commonwealth Minister for Industry and Resources in 2013 because criteria (a), (b) and (d) were found not to be satisfied.	15-year no-coverage
	Comet Ridge to Wallumbilla Loop	GLNG		15-year no-coverage determination granted by Commonwealth Minister for Industry and Resources in 2015 because criteria (a), (b) and (d) were found not to be satisfied.	

Source: NCC, Past Applications Register, http://ncc.gov.au/applications-past/past_applications.