



Australian Government
Productivity Commission

Examining Barriers to More Efficient Gas Markets

Productivity Commission
Research Paper

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The Productivity Commission

The Productivity Commission is the Australian Government's independent research and advisory body on a range of economic, social and environmental issues affecting the welfare of Australians. Its role, expressed most simply, is to help governments make better policies, in the long term interest of the Australian community.

The Commission's independence is underpinned by an Act of Parliament. Its processes and outputs are open to public scrutiny and are driven by concern for the wellbeing of the community as a whole.

Further information on the Productivity Commission can be obtained from the Commission's website (www.pc.gov.au).

Contents

Acknowledgments	v
Abbreviations and explanations	vi
Overview	1
1 About this report	25
1.1 The eastern Australian gas market is changing	25
1.2 Analytical approach	25
1.3 Conduct of the project	26
2 Framework for analysis	29
2.1 Characteristics of a well-functioning market	29
2.2 Putting issues in gas markets into an economic context	31
3 Overview of Australian gas markets	35
3.1 Australian gas markets	35
3.2 Growth in LNG exports and linkage to the Asia-Pacific	43
4 Designing and allocating gas exploration and production rights	55
4.1 What is a tenement?	56
4.2 Tenement design and the timing of exploration and production	58
4.3 Allocation of exploration licences	64
5 Managing conflicting land uses	77
5.1 Managing the effects on directly affected landholders	78
5.2 Managing the effects of gas exploration and production on the broader community	86
6 Policy issues in markets for transmission pipeline capacity	105
6.1 Pipeline capacity allocation and investment	106
6.2 Potential barriers to efficiency in transmission pipeline capacity markets	112

6.3	Assessing the case for policy change	117
7	A broad perspective on the case for policy reform	123
7.1	Structural adjustment and policy reform	124
7.2	Market power and policy reform	129
7.3	What role then for policy reform?	133
A	Conduct of the project	137
	References	141

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Paul Lindwall
Commissioner

31 March 2015

Abbreviations and explanations

Abbreviations

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
AIG	Australian Industry Group
AMDQ	Authorised Maximum Daily Quantity
APIA	Australian Pipeline Industry Association
APPEA	Australian Petroleum Production and Exploration Association
BREE	Bureau of Resources and Energy Economics
CGE	Computable general equilibrium
COAG	Council of Australian Governments
CSG	Coal seam gas
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ESAA	Energy Supply Association of Australia
EUAA	Energy Users Association of Australia
GDP	Gross domestic product
GJ	Gigajoule
IPART	Independent Pricing and Regulatory Tribunal
JCC	Japan Customs-cleared Crude
LNG	Liquefied natural gas
MLUF	Multiple Land Use Framework
MMBtu	Million British Thermal Units
Mtpa	Million tonnes per annum
NCC	National Competition Council

NGL	National Gas Law
NGR	National Gas Rules
PC	Productivity Commission
PJ	Petajoule
SCER	Standing Council on Energy and Resources
TJ	Terajoule

Explanations

Billion	The convention used for a billion is a thousand million (10^9).
Btu	British thermal unit, a measure of energy equivalent to 1055 joules.
Gigajoule	A measure of energy equivalent to one billion (10^9) joules
Joule	A unit of energy; 4184 joules are required to raise the temperature of one kilogram of water by one degree Celsius.
Megajoule	A measure of energy equivalent to one million (10^6) joules.
MMBtu	One million British thermal units, a measure of energy equivalent to 1.0551×10^9 joules, or 1.0551 gigajoules.
Petajoule	A measure of energy equivalent to one quadrillion (10^{15}) joules.
Terajoule	A measure of energy equivalent to one trillion (10^{12}) joules.

OVERVIEW

Key points

- The integration of the eastern Australian gas market with the Asia–Pacific market represents an opportunity for the Australian community to earn a higher return from its substantial non-renewable resources. This will result in a net benefit to the community.
- The opening of the export market is creating significant disruption for market participants and will lead to material costs for some gas users, including through higher prices. There are concerns about short-term gas shortages and some gas users have indicated that they are unable to secure supply contracts.
 - Policies that seek to counteract the pressures from structural adjustment arising from the opening of the export market, such as domestic gas reservation, could distort important signals for adjustment and are unlikely to be efficient or effective in the long run.
 - Governments should be mindful that policies that interfere with market signals could undermine investment incentives, including incentives to bring on new sources of gas supply.
- The mechanisms for allocating gas exploration and production rights should seek the optimal level and timing of such activities by companies that can perform them most efficiently.
 - Policies designed to accelerate production, such as use it or lose it mechanisms, risk bringing forward gas production in a way that reduces the benefits received by the community from the gas resource.
- The gas industry faces strong resistance from sections of the community, partly due to the poor early record of some companies in dealing with landholders and local communities. Some gas companies have increased their engagement efforts recently.
 - There is scope for improvements to legislated compensation provisions to better reflect the costs to landholders from negotiating land access agreements and from the decline in the value of their properties. There is also scope for measures to reduce the costs of negotiating land access agreements.
 - A well-designed voluntary industry-wide code of practice for community and landholder engagement may improve outcomes.
- Community concerns about the environmental and public health risks of coal seam gas (CSG) activities have led to CSG moratoria in Victoria and New South Wales.
 - The expected benefits of the moratoria must be weighed against their expected costs — higher gas prices for users and reduced royalty and taxation revenue for governments.
 - Sound risk management does not equate to eliminating all risk. The scientific evidence suggests that the technical challenges and risks can be managed through a well-designed regulatory regime, underpinned by effective monitoring and enforcement of compliance.
- Stakeholders have proposed changes to the way transmission capacity is allocated for some pipelines, including introducing open access principles and mandatory capacity trading provisions. Any benefits from these measures must be weighed against their costs, including the risk of undermining incentives for future investment in pipeline capacity.
- Some stakeholders have argued that gas producers and pipeline owners are exercising market power and distorting outcomes in the eastern Australian gas market. While the Commission has not presented any conclusions on this issue, the evidence used to support the claims of the existence and exercise of market power, such as higher prices or difficulties securing gas supply contracts, may reflect the risks and uncertainties in a market that is undergoing considerable structural adjustment.

Overview

The eastern Australian gas market is undergoing a period of rapid growth and transformation. The first shipment of liquefied natural gas (LNG) departed the Queensland port of Gladstone in January 2015, linking the last of Australia's three physically separated markets to international markets and exposing gas users on the east coast of Australia to market dynamics and prices in the Asia-Pacific region.

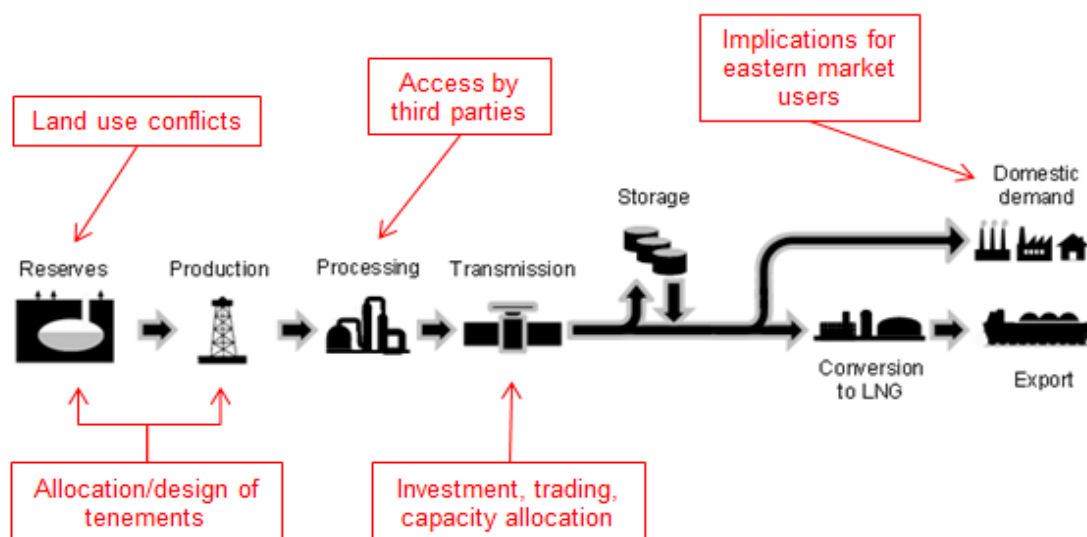
Expectations of higher gas prices and new sources of demand have created strong incentives for LNG producers to increase production, transmission and processing capacity. The level of future production depends on many factors, including LNG prices, which are linked to world oil prices, and domestic production costs. Estimates suggest that demand for gas in eastern Australia could increase more than threefold over the next 3–5 years, with around two-thirds of the volume of gas produced destined for export markets.

Much of the growth in production is expected to come from coal seam gas (CSG) fields in the Surat-Bowen basins in Queensland. While CSG production in those basins dates back to the 1990s, a tenfold increase in proven and probable reserves over the past decade has been one of the catalysts for the investments into export infrastructure on the east coast. The Queensland LNG projects are the first in the world to rely mainly on CSG.

The fundamental structural changes in the market are creating or exacerbating a number of policy pressure points for gas producers, gas users and the broader community. There has been a lot of recent commentary on the issues, but some of the debate and the policy responses so far have not been framed in an economic context.

In this research project, the Commission has sought to provide an economic perspective on selected policy issues (figure 1). The project focuses on the eastern Australian gas market but, as is the approach for all its work, the Commission examined the issues and evaluated policy proposals on the basis of whether they would be expected to improve the wellbeing of the community as a whole.

Figure 1 **The scope of the Commission's eastern Australian gas market project**



As part of the project, the Commission has developed an economic model of the eastern Australian gas market (box 1). The model used illustrative examples of hypothetical policy scenarios to complement the Commission's analysis.

Consequences of linking with the Asia–Pacific market

The linking of the eastern Australian gas market with the Asia–Pacific market has already had — and will continue to have — significant implications for market participants.

There is substantial disruption and uncertainty in the market

Many market participants are faced with the disruption and uncertainty caused by the surge in demand for gas. Some large gas users with long-term gas contracts due to expire this year and next have reported difficulties in securing new contracts. Many are also concerned about a lack of information on export commitments and anticipated production levels to gauge how much gas is expected to be available in the eastern Australian gas market in coming years. More specifically, some large gas users are concerned that there may be shortfalls in the eastern Australian gas market because the LNG projects may not have sufficient supply to meet their export commitments.

Box 1 Commission modelling of the eastern Australian gas market

The Commission has developed a partial equilibrium model that seeks to capture the underlying economic fundamentals of the eastern Australian gas market. The model is used to examine the effects of linking with the Asia–Pacific market, as well as selected policy issues, such as CSG moratoria and the effects of a domestic gas reservation policy. To test the sensitivity of model results, three different scenarios were estimated based on different estimates for LNG prices: a ‘low LNG price’ scenario, a ‘central LNG price’ scenario and a ‘high LNG price’ scenario.

The supply and demand sides of the market were represented in the model. Gas production, processing, transmission, storage and LNG conversion were modelled as separate activities in the supply chain. Demand for gas was disaggregated into demand from electricity generators, industry and mass market users. Exploration, distribution and retail were not explicitly modelled.

The geographical detail of the model captured key transmission pipelines linking major supply basins and demand centres in the eastern Australian gas market. Supply basins and demand centres were represented by ‘nodes’ in the model. Each supply basin contained up to ten fields, with production from each field limited by estimated gas reserves recoverable from that field.

The model was not designed to forecast prices, does not capture the full engineering detail of the gas market, and makes a number of simplifying assumptions about the structure of the market. Nevertheless, it provides a useful illustration of some of the mechanisms at play.

Details of the Commission’s modelling approach and the data used are included in appendix B.

Potential shortfalls in gas supply over the medium term are projected in the Australian Energy Market Operator’s 2014 Gas Statement of Opportunities — shortfalls are projected to occur in peak periods in New South Wales and throughout the year in Queensland in 2020.

Gas producers are also affected by significant uncertainty about key aspects of the market. In recent months, the price of oil has fallen significantly, with concomitant effects on LNG prices.¹ There have been construction delays and cost blowouts affecting some LNG projects and general uncertainty about the future performance and cost of new CSG wells. In January 2015, Shell Energy — a joint participant in the Arrow Energy LNG project — announced that the export project will not proceed, but that Arrow Energy will still be developing its gas resources. Some gas explorers and producers have also recently announced asset write-downs as a result of global and domestic factors.

Gas prices have risen and are likely to rise further

Wholesale trading of gas is dominated by long-term bilateral contracts between buyers and sellers. Contract prices are determined through negotiations and depend on a range of

¹ During the course of this project oil prices have fallen to levels not seen since 2009. Crude oil prices (as measured by the average spot price of Brent, Dubai and West Texas Intermediate) have fallen from about \$US105 (\$A115) per barrel in July 2014 to \$US55 (\$A70) in February 2015.

factors such as contract size and duration, reliability of supply and the relationship between gas suppliers and their customers.

Price data for bilateral contracts are not publicly available and at any rate, would be difficult to compare due to their bespoke nature. Some market analysis suggests that gas contract prices in the eastern Australian gas market have increased substantially — one market survey shows contract prices increasing from an average of \$3.50–\$5 per gigajoule (GJ) to \$5.50–\$10 per GJ between 2010 and 2014. The commencement of exports is likely to cause further increases in gas prices in the eastern Australian gas market. Forecasts suggest that prices for new contracts could increase by between 10–60 per cent from 2014 levels by 2020, depending largely on what happens in the Asia–Pacific market.

A common understanding is that prices in the eastern Australian gas market will eventually converge to an LNG netback price — the export price of LNG less the costs of transport and liquefaction — which has tended to be higher than historical prices in the eastern market. This is a good rule of thumb because prices for LNG exports represent the opportunity cost of supplying gas to the eastern market. However, there are many factors that could cause prices on the east coast to diverge from the LNG netback price at any particular time (box 2). For this reason, attempts to reverse engineer an estimate of the efficient prices in the eastern Australian gas market from LNG prices, or to determine whether there is a policy problem from any discrepancy, are problematic.

Box 2 Factors that could influence gas prices in the eastern Australian gas market

Prices in the eastern Australian gas market could be influenced by many potential factors and may diverge from LNG netback prices at any given time.

- Uncertainty about future LNG prices coupled with the lumpy nature of investment in LNG facilities and lags in bringing those facilities online could cause prices in the eastern Australian gas market to temporarily under or overshoot LNG netback prices. A complicating factor is that most current LNG contracts are explicitly linked to world oil prices, which have fallen substantially recently both in US dollar terms and Australian dollar terms.
- Long-term contracts that have historically dominated the eastern Australian gas market can mean that prices on the east coast would be slow to respond to unexpected changes in the Asia–Pacific market. The eastern Australian gas market is not as well developed and does not have the liquidity or depth of gas markets in some other countries.
- Export contract conditions, including penalty clauses for failure to meet the supply commitments and limits on the ability to substitute gas from sources elsewhere (including overseas), could mean that any supply constraints would be borne by gas users in the eastern Australian gas market. Uncertainties about well deliverability and regulatory impediments to increasing supply are particularly important in this context.

There will be costs for some, but the community will gain overall

The effect of rising gas prices on residential, commercial and industrial gas users will vary depending on a number of factors, including: the gas intensity of the user's current operations; the cost of switching to alternative fuel sources or products; and (for commercial and industrial users) the capacity to pass on some or all of the price increases to consumers.

The opening of the export market will lead to material costs for some heavy users of gas in the manufacturing sector, including a number of large manufacturers that use gas as a feedstock to produce chemical or plastic products.² The Plastics and Chemicals Industry Association said that those companies are unable to switch to alternative feedstock and, because they are trade-exposed, they would have limited capacity to pass on the increase in cost to consumers. Participants in this project from a range of sectors suggested that if the consequences of linking with the Asia-Pacific market — including the reported inability to secure gas supply contracts — are not addressed, they may be forced to reduce output or exit Australian manufacturing altogether.

Markets are dynamic and participants need to continually adapt to a multitude of forces including the entry of new competitors, the emergence of new technologies and changes in consumer preferences. The fundamental driving force behind the increase in gas prices for gas users on the east coast is the increase in the *value* of the gas. It is a direct result of gas producers removing a barrier that previously prevented them from accessing markets that place a higher value on the gas from the east coast of Australia than domestic users.

Australia's gas resources are owned by the Crown and gas producers pay royalties and taxes on the value of the gas they produce. The opening of the export market for eastern Australian gas creates an opportunity to receive a higher return for this resource. The broader community benefits indirectly, but materially, through a higher flow of royalty and taxation revenue to Australian governments, which is subsequently invested in a range of areas including physical or human capital for the benefit of current and future generations.

Structural adjustment is not unique to gas markets and is ultimately a process that shifts resources to more efficient production practices and to the supply of goods and services that create more value for consumers. Such movement of resources improves the performance of the Australian economy over time, improving the welfare of the Australian community as a whole.

Structural adjustment regrettably imposes costs on some individuals, regions and industries, while others will benefit. How those costs and benefits will be distributed across the Australian community is influenced by a number of factors. However, this does not change the core premise that it is no longer *efficient*, or in the best interests of the

² There are estimates that 25 per cent of gas used in New South Wales is by companies that use it as a feedstock.

Australian community, to sell gas at prices that prevailed before the linkage to the Asia–Pacific market.

This is not to say that the effects of linking with export markets should be ignored by governments. Instead, the process of structural adjustment increases the imperative for reform — it also magnifies the consequences of policy errors. The rapid growth and transformation of the eastern Australian gas market puts a premium on policies that would facilitate (rather than impede) adjustment and remove distortions that prevent the reallocation of resources to their highest value uses.

Achieving this objective would require ensuring that policy settings are sound across the supply chain, including:

- the design and allocation of the rights for gas exploration and production to establish the correct incentives for those activities and ensure that they are undertaken by those who could do so most efficiently
- policies and measures to resolve the land use conflicts arising as a result of gas activities, in a way that generates the greatest net benefit to the community
- policies to ensure that gas transmission markets are operating efficiently, including facilitating the efficient allocation of pipeline capacity and maintaining the correct incentives for investment in new capacity.

Allocation of gas tenements

The design of the rights to explore and produce gas resources (gas tenements) and the method by which those rights are allocated could affect efficiency in gas markets. The objective of tenement regimes should be to maximise resource rent by allocating exploration and production rights to parties that can undertake those activities most efficiently, and to facilitate the optimal level and timing of exploration and production.

Some large industrial gas users have suggested that gas companies are ‘hoarding’ reserves, restricting the quantity of gas available, and have advocated the introduction of use it or lose it requirements on holders of gas tenements to accelerate gas production.

There is insufficient evidence available to the Commission to determine whether gas producers are restricting the quantity of gas available by hoarding reserves. However, even where some gas reserves are not currently being developed, this does not of itself suggest that producers are distorting market outcomes. Production decisions in particular fields depend on current and expected development costs and prices — some gas sources are higher cost than others and may not be profitable to develop at a particular time.

In situations where a reserve is not being developed for valid commercial reasons, a use it or lose it policy could accelerate or bring forward gas production in a way that reduces the returns received by the community from the gas resource. Even if the gas industry were

hoarding reserves to exercise market power, a use it or lose it policy would be unlikely to deliver material benefits for eastern market gas users. There is no assurance that any additional gas would be channelled to domestic users rather than export markets. One likely consequence of the policy would be to reduce the incentives to bring on new sources of supply.

There may be merit in a closer examination of the existing arrangements for the initial allocation of tenements to gas companies. Mechanisms that promote the allocation of tenements to those who can make the best use of them, including the ability to trade exploration and production licences in secondary markets, are a strong safeguard against inefficient hoarding of gas reserves. The Australian and Queensland Governments have recently introduced cash bidding for some gas resources, and these schemes could provide insights into auction design and the scope for their broader application.

Conflicting land uses — a challenge for governments

The rapid growth of the gas industry and its progressive encroachment onto private land has exposed some sharp conflicts between existing landholders, local communities and the gas industry. Exercising the rights for onshore gas exploration and production can generate two types of land use conflicts — the effects on the landholders hosting the activity, and broader economic, amenity, social and environmental effects on the community.

The gas industry has faced strong resistance to its operations from some parts of the community. Some of this resistance is a consequence of strongly held views about the risks of gas exploration and production activities, particularly those relating to CSG. However, this is also partly a consequence of poor behaviour in the past by some members of the gas industry in engaging with landholders — a fact acknowledged by the industry. Some examples of this behaviour include: failing to communicate and provide adequate notice about planned activities; and failing to supervise the activities of contractors. Less than adequate recognition of local communities by gas companies may also have contributed to the evident resistance to gas exploration and production.

Designing a policy regime to manage the effects of gas exploration and production on other land users — while balancing all of the competing interests — is very challenging. It is unsurprising that governments have struggled to develop a timely policy response that balances the sincere but conflicting concerns of landholders, industry, the local community and Australia as a whole.

Managing the direct costs of land access for gas activities

Most of the private land for which access is being sought by gas companies is currently used for agriculture. Landholders do not have the right to deny gas companies access to

their properties. However, they can incur costs, from losing the use of their land, possible damage to property and general disruption.

The direct effects on landholders hosting gas activities and their neighbours are currently addressed through a right to compensation from the gas company. This is the best mechanism for the task because it enables outcomes that are customised for particular circumstances, the relevant parties are few and easy to identify, and the costs incurred by landholders are *relatively* easy to quantify.

While legislation specifies the types of costs that a landholder can be compensated for, these are typically no more than a guide, as in most cases the terms of access are determined through negotiation between the gas company and the landholder. In some cases, especially recently, gas companies are offering better terms than required under the legislation. Nevertheless, there is scope for improvement in both the legislated compensation provisions and the arrangements for negotiations between gas companies and landholders.

An objective and direct measure of the economic cost of gas activities to the landholder, encompassing the different types of damage, is the decline in the market value of the landholder's property (land and any improvements). This market value reflects the highest value uses of the land with and without the gas activities.

However, in most jurisdictions the decline in the market value of the landholder's property is not recognised explicitly in legislation as an overarching principle for setting compensation. In most jurisdictions, the legislation provides a list of specific heads of compensation. This approach risks omitting important factors. For example, in some cases the loss of amenity for the landholder from the gas activities on their land is not formally recognised as a basis for compensation.

A sound compensation regime that helps align the relevant interests will best support the joint incentive to maintain a cooperative rather than adversarial relationship, and can reduce the costs incurred in negotiating such access agreements.

Land access negotiations typically involve a large volume of technical, legal and financial information and require some expertise in undertaking negotiations. In a 2013 study the Commission recommended that resource exploration companies be required to compensate landholders for reasonable costs of professional advice due to asymmetries between the landholder and gas companies in the availability of information and in negotiation experience. However, in some jurisdictions, landholders are not explicitly entitled to such compensation.

The costs of negotiating access agreements could be reduced through the development of template access agreements and negotiation guides for landholders. The peak bodies representing the gas industry and agricultural land users are best placed to prepare such materials.

Landholders may also be assisted by increased transparency on the pricing outcomes from past agreements. In Queensland, there are plans to develop a register of land access agreements and in New South Wales, the Independent Pricing and Review Tribunal has been asked to collect information from past agreements to develop compensation benchmarks for the parties. At this stage, it is too early to assess the merits of these approaches. Nevertheless, the Commission is supportive of efforts to reduce the transaction costs and improve transparency for landholders and gas companies in negotiating such agreements. Provided the costs of doing so are reasonable, there is scope for measures such as the publication of compensation benchmarks by governments.

Social licences to operate and community engagement initiatives

Further thought by explorers and producers on early engagement directly with communities, rather than simply on compensation for landholders, is needed.

While some gas companies have had a poor early record in managing their relationships with landholders and local communities, more recently, companies have increased their efforts to obtain a ‘social licence to operate’. Some gas companies have contributed to local communities through the funding of local services or infrastructure.

Governments have little role where gas companies make voluntary efforts to secure support for gas activities. However, there are risks in *requiring* gas companies to contribute to local communities to gain community acceptance of their operations. The change in the bargaining power of the parties could create incentives for rent seeking and hold out for members of local communities. A social licence would also not necessarily be an accurate reflection of the best interests across the whole jurisdiction, or even the region hosting the gas activities. Local communities are not homogeneous and there is evidence of conflicting attitudes to the gas industry within them, so achieving consensus would be difficult.

Ultimately, some gas companies have exceeded their statutory obligations on landholder compensation, and in contributing to local communities. However, provision of financial contributions by the industry to gain community acceptance should not be a matter for additional regulation.

A code of practice and an independent agency for community engagement

A well-designed uniform voluntary code of practice outlining the principles and elements of best practice community engagement for the gas industry may improve outcomes and address expectations of future interactions on both sides. Other sectors that have faced similar issues with community resistance, such as the wind energy industry, have adopted this approach.

The code should be developed in consultation with, and be endorsed by, key industry and landholder groups. The COAG Energy Council may be well placed to assist the development of the code given its previous involvement in developing relevant policy documents, such as the National Harmonised Regulatory Framework for Natural Gas from Coal Seams, and the Multiple Land Use Framework.

There may also be a case for investigating the merits of a body that assists the interactions of landholders, local communities and the gas industry. The Queensland GasFields Commission — an independent statutory agency — was established in 2013. The agency has been given powers to collect and disseminate information, advise government and directly engage stakeholders to resolve land coexistence issues on the ground. The costs and benefits of the GasFields Commission model could be evaluated for possible application in other states.

Policies to deal with economic and amenity effects on local communities

The activities of a gas company can lead to a number of economic and amenity effects for local communities. Some are positive, such as improved employment opportunities and increased economic activity in the region. Some are negative, for example the noise, dust and visual disturbance arising from gas activities, as well as increased demand for public infrastructure and services. These effects vary over time, depending on the stage of exploration or production.

Some of the adverse effects can best be addressed through broader policy settings. For example, it is important to ensure that the arrangements for the funding and provision of infrastructure are operating efficiently. This would include ensuring that the relevant local councils are adequately resourced to perform their functions, including their responsibilities with respect to public infrastructure, or providing funding support from other levels of government.

In some jurisdictions, governments have also committed some of the gas royalty receipts to the regions that host the gas industry, in an effort to facilitate community acceptance of gas activities.

There is a clear distinction between gas companies undertaking voluntary initiatives that may address some of the adverse economic and amenity effects of their operations on local communities, and governments earmarking some of the royalties for the benefit of a local community.

There are considerable risks of inefficient outcomes from programs that seek to return a share of the royalties to specific regions, because they could distort public spending decisions away from projects that could deliver a greater net benefit to the community. There are also potentially adverse equity implications — such approaches transfer the

benefit of gas production from the general population to communities located in the vicinity of the gas industry's operations.

Land planning and development approvals

Land planning policies play an important role in addressing land use conflicts at the local and broader community level. Such policies should ideally be based on the principle of maximising the benefit to the community as a whole from the use of the land.

In recent years, some governments introduced policies to protect existing agricultural and residential land uses as an *a priori* objective, prohibiting CSG activities in some areas. In at least one jurisdiction, this approach may have contributed to the write-off of large proven reserves.

Land use planning policy cannot and should not be divorced from acknowledging existing land uses. Introducing new uses on the land such as gas exploration and production will involve costs for the incumbent landholders. These costs may sometimes outweigh the benefits of gas activities. However, if governments seek to revise land planning protections to favour existing land uses, a transparent consideration of the costs and benefits (including the loss of royalties and the implications for taxation revenues) should be undertaken.

Gas exploration and production activity tends to be concentrated in particular regions, and development approval decisions may need to reflect the cumulative impacts of the projects on the region, rather than simply assessing each project on its own merits. When they are done well, strategic assessments that focus on the costs and benefits of alternative land uses at a broader regional level can assist development approval decisions.

Managing the environmental and public health risks of CSG

Over the past decade, much of the debate and regulatory policy developments in the eastern Australian gas market have focused on managing the potential environmental and health and safety effects of the exploration and production of CSG.

There have been strong community concerns that the water-intensive nature of CSG exploration and production would deplete groundwater resources and have adverse consequences for water tables. Some members of the community are also concerned about the risks of groundwater contamination, the disposal of produced water and other by-products, as well as the subsequent rehabilitation of the land.

These considerations have prompted the NSW Government to introduce a moratorium on new CSG exploration licences and on CSG production in water catchments. In Victoria, a moratorium on all hydraulic fracturing and new onshore exploration licences has been in place since 2012. A further hold on all exploration drilling for existing licences was added in 2014.

Moratoria are not costless ...

Concerns about the environmental and public health effects of CSG activities are undoubtedly important. There are several tools through which these concerns could be addressed — moratoria are but one of them. However, whatever policy tool is implemented, the expected benefits from reducing the environmental and public health risks from CSG activity should be assessed against the expected costs to the gas industry, gas users and the Australian community as a whole.

Estimating the costs of the moratoria is extremely difficult, not least because the policies themselves are preventing exploration activity that could provide a measure of the size and commercial viability of affected gas reserves. Estimates of expected production costs and well deliverability fluctuate considerably on the back of limited, and in many cases, nonexistent data. Nevertheless, the underlying mechanisms through which the eastern market can be affected by the imposition of moratoria do not change.

The moratoria on CSG production in New South Wales and Victoria impose a constraint on the supply of gas in the eastern Australian gas market and may necessitate the development of more expensive sources of supply. Where this occurs, a cost will be imposed on some, or all, of the gas industry, domestic gas users and the broader community. The form that these costs take, and their distribution, depends on a number of factors and could change over time. Where moratoria reduce gas production but do not affect the quantity of gas exported (for example, where all export commitments are already locked-in through long-term contracts) the effect will be largely felt by gas users within the eastern Australian gas market through higher prices.

In the longer term, reductions in production resulting from the moratoria could be reflected in lower gas supply volumes (including for export) and, as a consequence, reduced royalty and taxation revenue. The gas industry and the broader community would bear the brunt of those costs. The costs would be greater if LNG prices are high enough to create the incentive for a significant increase in production on the east coast, but gas producers are prevented from doing so by the moratoria.

... and those costs could be felt for some time

There is typically a delay of 3–6 years between investments in gas exploration and production and the actual supply of gas to users, and such investments have large upfront costs. This means that moratoria could lock in some higher cost production and the effects could continue to play out for several years after the moratoria are lifted. The costs would be magnified if there is uncertainty about the duration of the moratoria, as this may lead to gas and pipeline companies delaying investment decisions until they receive a clear signal about future policy from the government.

Moratoria could encourage wasteful behaviour

To the extent that moratoria (or a threat of them) are driven by community pressure on their respective governments, they could also distort the incentives of the gas industry, landholders and local communities. For example, they could encourage gas companies to secure landholder and community support through increased financial contributions, where the issue may be best resolved through a sound, transparent and credible regulatory framework. In effect, moratoria could increase pressure for other actions by stakeholders that may not necessarily be motivated by the interests of the broader community.

Sound risk management does not equate to eliminating all risk

In recent years there has been a substantial research effort specific to CSG activities in Australia carried out by universities, government agencies and CSG proponents. However, there are still uncertainties about some of the long-term effects. There are gaps in baseline data, hindering effective monitoring, and there is also a need for more information on the cumulative effects of multiple activities on the land.

The scientific uncertainty about some of the environmental and public health effects of CSG activities requires governments to be cautious when determining the regulatory settings. However, no activity can be risk free, and any type of land use, including agriculture and extraction of any sub-surface resources is likely to create some environmental consequences, not all of them foreseeable at the outset.

Sound risk management recognises that there are trade-offs in reducing risk. These trade-offs include the direct costs of moratoria discussed above, as well as the possibility of distortions in favour of higher risk activities with less intensive monitoring and regulation. Crucially, the burden of regulation and supervision should be consistent and coherent with the risks of the activity. In the case of CSG, governments that have resorted to moratoria, and the community groups opposed to the CSG industry, may have been seeking a higher standard of risk management from CSG activities than what applies for many other land uses.

Scientific evidence suggests that CSG risks can be managed — but enforcement and provisions for rehabilitation are crucial

A comprehensive scientific and policy review of CSG by the NSW Chief Scientist and Engineer concluded:

CSG extraction and related technologies are mature and Australia is well equipped to manage their application ... The independent petroleum engineering, geological and geophysical experts advising the Review consider that such technologies (including fracture stimulation and horizontal drilling technologies), with appropriate safeguards, are suitable for use in many parts of the sedimentary basins in NSW, noting that drilling in any new location is, to an extent, a

learning-by-doing activity as there will always be local geological attributes specific to an individual resource development.

The broad regulatory frameworks to manage the risks of CSG activities exist in all jurisdictions. Australian governments have a suite of regulatory tools at their disposal, including: environmental impact assessment processes; petroleum regulations governing the construction, operation and decommissioning of gas wells; water planning and management regulations; and chemical safety regimes.

However, the effectiveness of the regulatory regimes, and ultimately the community's confidence that the risks are being adequately managed, rests on the robustness of the monitoring regime and enforcement of compliance. The review by the NSW Chief Scientist and Engineer, as well as a recent review by the Victorian Gas Market Taskforce, identified the need for some improvements in those areas in their respective jurisdictions.

There is also a strong case for the use of environmental insurance and assurance mechanisms funded by the gas industry, to ensure that the land affected by gas activities will be rehabilitated on conclusion of the project, and that those considerations factor in the gas company's decisions from the outset. Instruments such as environmental bonds are widely used in environmental regulation across Australia, and should apply to gas activities (including CSG), provided the burden on gas companies is proportionate to the level of risk.

A policy framework to manage land use issues

Ultimately, designing an efficient and equitable policy regime that addresses the multitude of land use issues that could arise from the expansion of the gas industry onto private land is extremely challenging. Governments need to address the legitimate concerns of the community about the broader effects of gas activities through evidence-based regulations and policies that are proportionate to the risks and are aligned with the costs and benefits of alternative uses of the land. The onus is on the gas industry to improve its standing in the communities in which it operates.

A policy framework that identifies the effects of gas activities, affected parties and mechanisms to address those effects could bring clarity to the policy debate. The Commission has proposed a framework to assist policy makers and stakeholders (table 1).

Table 1 A framework for managing the land use issues

<i>Issue</i>	<i>Who is affected?</i>	<i>Primary mechanism to address</i>	<i>Roles of the parties</i>	<i>Supporting mechanisms</i>
Direct costs of land access for gas activities	Landholders that host gas activities	Negotiated compensation from gas company to landholder that reflects the costs to the landholders from negotiating land access agreements and from the decline in the value of their properties	State governments to administer statutory regime for compensation	Facilitation of negotiations through agreement templates and guidelines developed by gas industry and landholder groups
	Owners of damaged neighbouring properties	Compensation from gas company to neighbours for incidental damage	Landholder and gas company to negotiate access terms	Publication of compensation benchmarks by state governments if costs are reasonable
Environmental and public health effects of gas activities	Local and broader community	Purpose-specific regulation	State governments to administer and enforce regulation Industry to comply with regulatory regime	Risk-reflective environmental insurance/assurance provided by gas companies for rehabilitation of adverse effects
Economic and amenity effects on local communities	Local communities	Land use planning instruments	State governments through the administration of land use planning regimes	Voluntary initiatives by gas industry to address adverse economic and amenity effects on local communities
		Arrangements for provision and funding of public infrastructure	Commonwealth, state and local governments to address public infrastructure issues	
Social effects of gas activities	Local communities	Development of voluntary code of practice for community engagement for the gas industry	Industry and landholder groups to develop the code Australian Government to coordinate	Potential merit in an independent agency to manage industry and community interactions on the ground

Issues in transmission pipeline capacity markets

Gas transmission pipelines are a key part of the gas supply chain. Further development of the eastern Australian gas market would require further investment in gas transmission pipelines. The consequences of barriers to efficient investments and other inefficiencies in transmission markets could be significant.

Previous gas market reviews and gas market participants have argued that there are potential barriers to improved outcomes in transmission pipeline capacity markets. Some of the issues raised relate to the operation of the contract carriage model for allocating pipeline capacity (box 3). There are also concerns about the effects of economic regulation under the National Gas Law, and arrangements under the market carriage model on incentives to make efficient investments in pipeline infrastructure.

Box 3 The contract carriage and market carriage models

Market carriage model

In the Victorian Declared Transmission System (DTS) pipeline capacity rights are allocated under the market carriage model. Under this model, capacity is bundled with gas purchased in the wholesale gas market. The Australian Energy Market Operator clears the wholesale gas market on an intra-day basis according to a merit order based on market participants' bids to purchase gas. Users do not reserve physical capacity (meaning there are no long-term capacity rights).

Contract carriage model

Outside the DTS, pipeline capacity is allocated under the contract carriage model. Under this model, allocation of capacity occurs independently from wholesale gas markets through contracts between the pipeline owner and user ('contract holder'). Pipeline owners can reallocate unused contracted pipeline capacity to other users by selling 'as available' capacity rights. Contract holders can sell unused capacity in secondary pipeline capacity markets.

Stakeholder criticisms of the contract carriage model and proposals for policy change

Much of the debate concerning how transmission pipeline capacity should be allocated has centred on stakeholders' views of the relative merits of the market carriage and contract carriage models. The advantages of each model will be more or less important in different circumstances. Some gas market stakeholders consider that the market carriage model, which does not require firm capacity rights to be defined, could provide advantages in 'meshed' pipeline networks (which have multiple injection and withdrawal points) where it is difficult to cost-effectively define capacity rights. In point-to-point pipeline networks and where there is considerable scope for future pipeline investments, the contract carriage model (which is considered by some gas market stakeholders to promote more efficient investment) may be the most suitable model. The strengths and weaknesses of elements of each model should be considered in the context of the expected future needs of Australia's gas markets.

Lack of transparent information and transaction costs

Previous gas market reviews have highlighted a lack of transparent information under the contract carriage model on the identity of pipeline capacity contract holders, pipeline usage

rates, and the availability and price of capacity in secondary pipeline capacity markets. A lack of transparent information regarding the availability of pipeline capacity, and the higher transaction costs that this entails, are potential barriers to trading capacity in secondary pipeline capacity markets. This could inhibit the entry of new suppliers into retail markets, and could limit the efficiency and liquidity of wholesale supply hubs, which depend on flexible and short-term access to pipeline capacity. These concerns have prompted calls for policy change from some gas market participants, including the mandatory and timely reporting of all significant market data.

Transaction costs are not the only factors that potentially influence outcomes in secondary pipeline capacity markets. The extent of trading in secondary pipeline capacity markets also depends on, among other things, whether there are buyers and sellers that place different valuations on pipeline capacity at a given point in time, and whether capacity is available in a form required by buyers (for example, some buyers may require firm capacity rights).

The COAG Energy Council is currently progressing reforms, scheduled to be completed in 2016, that are intended to increase the information available to market participants and to develop standardised secondary market contracts. While these reforms could help to increase the liquidity of the eastern market and promote entry in upstream and downstream markets, the extent to which they provide net benefits will partly depend on how much demand there is for capacity in secondary pipeline capacity markets and the costs imposed on stakeholders from increased data-reporting requirements. Any consideration of further policy change would ideally occur after the current reforms have been in place long enough to be bedded down and properly evaluated.

Incentives to hoard capacity

Reviews undertaken for the Australian Energy Market Commission and Australian Energy Market Operator stated that pipeline users with firm capacity rights may have an ability and incentive to ‘hoard’ their capacity in order to limit competition in the downstream markets in which they operate. Proposals for policy change include extending the open access principles that apply under the market carriage model to elsewhere in the eastern market, and calls for the introduction of mandatory pipeline capacity trading provisions that apply in other countries, including the European Union and the United States.

On the one hand, adopting open access principles or introducing mandatory pipeline capacity trading provisions could in some cases facilitate the reallocation of pipeline capacity to higher value uses. Making access to secondary pipeline capacity easier for market participants could encourage more efficient responses to demand and supply imbalances in different parts of the eastern Australian gas market and assist the development of wholesale spot markets.

On the other hand, what may appear to be inefficient hoarding of capacity may instead be commercial behaviour that is consistent with outcomes from effectively competitive

markets, and further regulation may not be warranted. Also, as noted above, secondary capacity trading could be impeded by transaction costs and other constraints. Holders of firm capacity rights may also be retaining some spare capacity as a risk management tool in an environment of market uncertainty.

Introducing the above proposed policy changes could put at risk the investments in gas transmission pipelines that would be needed in response to further development of the eastern Australian gas market. For example, some previous gas market reviews have highlighted concerns that the market carriage model may not create sufficient incentives for investment, principally because the absence of long-term firm capacity rights means that pipeline users have little incentive to underwrite pipeline investments. Similar risks would arise from adopting capacity trading provisions that apply in other countries. More generally, the performance of such provisions in other countries is unlikely to provide clear policy guidance in Australia, due to fundamental differences in market structure and size.

Policies to restrict exports are costly and inefficient

The structural pressures from the rapid growth and transformation of the eastern Australian gas market have led to calls from some gas market stakeholders for policies to restrict the exports of gas to increase supply and drive down prices for domestic users. A formal domestic gas reservation policy has operated in Western Australia since 2006, with LNG producers required to reserve up to 15 per cent of production for the domestic market. A legislated provision for gas reservation also exists in Queensland, but the policy has not been exercised to date.

Another proposal is the introduction of a ‘national interest test’, where exports are conditional on approval by government — a policy with some similarities to a regime that applies in the United States. While this proposal is slightly different in design from traditional reservation policies, the underlying mechanism is the same — a diversion of some gas supply to domestic users that would have otherwise been destined for export.

Some gas market stakeholders have commissioned studies which showed that such policies would deliver a net benefit to the Australian community. However, those studies are based on ‘multiplier’ methodology that assumes that the economy will not adjust to the contraction of a sector and that resources will simply become redundant and will not find alternative uses in other sectors. This approach tends to significantly overestimate the benefits of domestic gas reservation, and as such, studies based on multiplier methodology do not provide strong evidence for informing the policy debate.

Other studies that adopted more realistic assumptions about the movement of resources across the Australian economy concluded that reservation policies would impose a net cost on the community. The Commission’s analysis and modelling indicate that a reservation policy would impose a cost on gas producers and ultimately on the broader community because it would divert the supply of gas from its highest value use, reflected in the higher

prices prevailing in the Asia–Pacific. The cost to the community of diverting the gas from the export market to the eastern Australian gas market would outweigh any gains to domestic users, which are of themselves far from guaranteed.

Over the longer term, a reservation policy that diverts the supply of gas from higher value uses in the Asia–Pacific market would reduce the return on, and create a disincentive for, investment in new supply sources. Domestic gas reservation may ultimately be costly but ineffective in preventing wholesale gas prices for domestic users in the eastern market from rising in the future.

In addition, such policies are administratively difficult for governments to implement due to the need to recalibrate the policy on the basis of accurate and updated forecasts of domestic supply and demand.

Arguments concerning market power in upstream markets — a note of caution

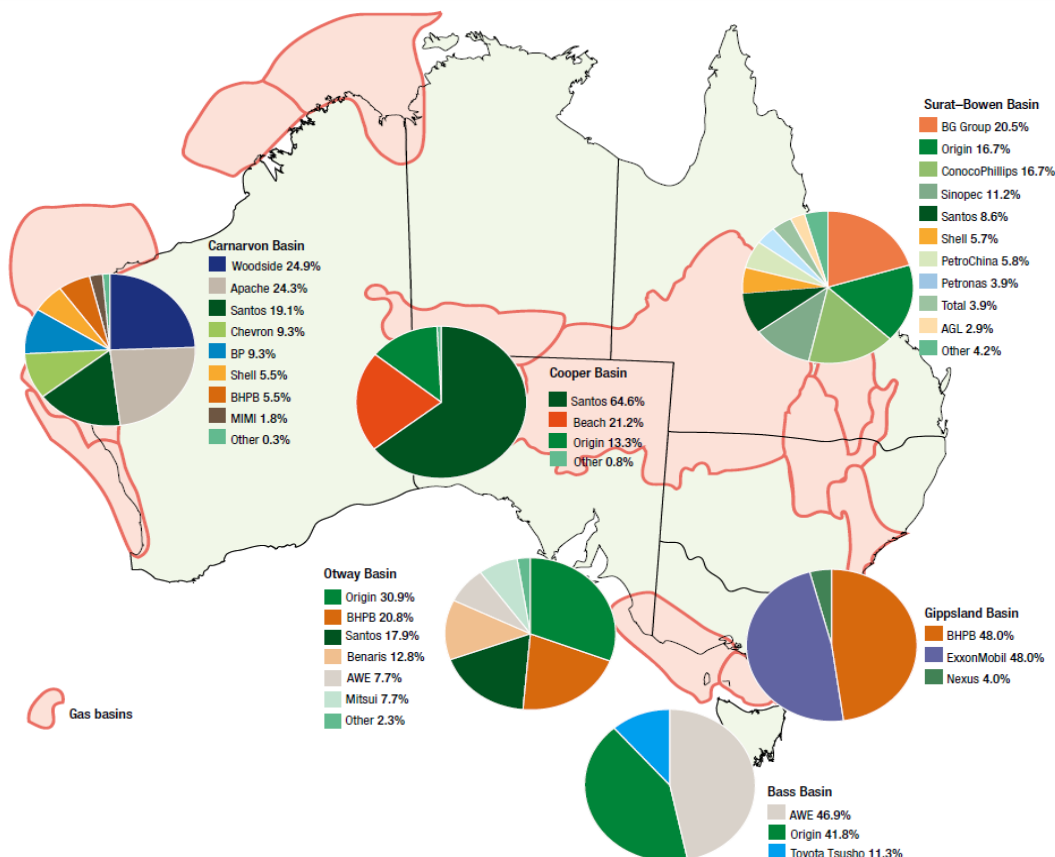
Concerns about the existence and exercise of market power in upstream gas markets feature prominently in the policy debate and the issue was central for many participants in this project. A comprehensive assessment of the existence and exercise of market power in upstream gas markets is outside the scope of this project — caution is warranted in drawing firm conclusions on the extent of market power based on evidence that has been put forward to date.

Market concentration is important but it is not the only factor

Some characteristics of gas markets could (but do not necessarily) make them vulnerable to the presence and exercise of market power. Upstream gas markets in parts of Australia have a small number of suppliers (figure 2). Joint venture and marketing arrangements that are entered into by gas producers can further increase market concentration. Some companies are also vertically integrated, where a gas explorer is a producer and seller in wholesale and retail markets.

While market structure is one relevant consideration, it is not of itself sufficient evidence of the existence or exercise of enduring market power. Other factors, such as the threat of entry by new suppliers, the availability and cost of switching to substitute energy sources and any countervailing power of buyers are also important. Such countervailing factors are likely to have a greater effect in the long term than the short term.

Figure 2 **Market shares in domestic gas production, by basin^a**
2012–13



^a Excludes the Joint Petroleum Development Area in the Timor Sea.

For example, over the longer term, users may be better able to substitute to alternative sources of energy, diminishing any capacity that might exist for gas producers to exercise market power (substitution may be more difficult or impossible when gas is used as a feedstock). More fundamentally, even if some gas producers have market power at any given point in time, the associated profits and prices can act as a signal to rivals, with the entry of competitors into the market constraining, and over time eroding, this power.

The integration of the eastern Australian gas market with the Asia-Pacific market should facilitate conditions for greater competition in upstream markets. The expectations of higher prices and increased size of the market may be leading to new entry into upstream gas markets, and an increased threat of future entry. The growth of the CSG industry in particular appears to have led to considerable new entry in Queensland's Surat-Bowen basins.

Difficulties in securing contracts can occur in competitive markets

Some gas market stakeholders have argued that gas producers in the eastern Australian gas market have market power, and that the exercise of this power is affecting market outcomes, including the ability to secure a contract on competitive terms for gas purchases. A number of large industrial gas users have indicated that they are unable to secure contracts at *any* price (or that there is a risk of this happening). Some users have suggested that this too is a manifestation of the exercise of market power.

However, as noted above, higher prices in the eastern market are an expected consequence of linking with export markets, and can be consistent with outcomes in markets characterised by effective competition. Even if the prices temporarily exceed the LNG netback price, this may be a reflection of producers managing their risk, including the prospect of penalties and reputational damage for not meeting their export commitments, in a period of market uncertainty (box 2). Large sunk costs and long investment lags can diminish the threat of entry and the competitive constraint that this can impose on incumbent producers. As a general principle, however, higher prices should lead to new supply, with a lag.

Reluctance to enter into supply commitments with gas users may be commercially rational behaviour in a highly uncertain market environment. Producers may be unable to charge prices in the eastern market that are high enough to compensate them for foregone export revenues and other costs of not fulfilling their export contracts, which may not allow for substitution from other supply sources. The difficulties reported by large gas users may also in part be a transitional issue that may resolve as the current disruption in the eastern Australian gas market settles.

Policy intervention could be aimed at issues that are transitional in nature, or will eventually be resolved efficiently by market participants. Proposals to address perceived problems with market power should not be introduced or applied unless there is sufficient evidence of the existence and exercise of enduring market power and robust analysis that the intervention will lead to a net benefit for the community as a whole. There is also a need for strong caution when considering applying existing competition law provisions, such as the application of third party access regulation for gas processing facilities (box 4).

A more comprehensive investigation of market power issues would be required to draw conclusions on whether there is a role for further policy intervention in upstream gas markets. The Australian Government's 2014 *Energy Green Paper* canvassed a gas market competition review by either the Australian Competition and Consumer Commission or the Productivity Commission.

Box 4 **The costs of regulating access to gas processing facilities**

Third party access regulation already applies to gas transmission and distribution pipelines under the National Gas Law and some stakeholders proposed extending this arrangement to gas processing facilities.

However, denial of access to a gas processing facility is not necessarily evidence of the exercise of market power — there can be valid commercial reasons for the owners of gas processing facilities to deny third party access. There are coordination issues and costs from sharing a gas processing facility with other parties. These can include the need for plant modifications to ensure that the facility is compatible with the particular chemical composition of a third party's gas, and loss of flexibility in operations and investments.

Beyond this, there are a number of other issues with the proposal. Part IIIA of the *Competition and Consumer Act 2010* (Cwlth), which sets out the National Access Regime, contains a number of threshold requirements for its application. These include (among others): a requirement that the declared service is of national significance; a requirement that it is uneconomical to develop another facility; and an exemption for production processes. Regulating access to gas processing services could set a precedent that results in the expanded application of third party access regulation. In its 2013 review of the National Access Regime, the Commission was particularly concerned about proposals to increase the scope of the Regime, including broadening the types of infrastructure services that could be subject to third party access.

There are also more general costs from this type of regulation, including:

- reduced incentives for new investment by gas processing facility owners — third party access regulation can distort investment incentives if it asymmetrically expropriates above normal returns without compensating the owner for the downside risk
- reduced incentives for investment by third parties — third party access tends to lock in the infrastructure technology used by the incumbent
- regulatory error
- administrative and compliance costs.

Concluding comments

The integration of the eastern Australian gas market into the Asia–Pacific market has already had, and will continue to have, significant implications for eastern Australian gas market participants. The process is creating strong structural pressures and imposes costs on gas users. Ultimately, however, the broader Australian community will benefit from the rise in the price (and volume) of the gas produced on the east coast of Australia. Policies that impede or counteract this process of structural adjustment could distort important signals for adjustment and are unlikely to be efficient or effective in the long run.

Nevertheless, the effects of international integration are increasing the imperative for sound evidence-based policies across the gas supply chain. There is much to gain for the Australian community from successfully meeting this challenge.

1 About this report

1.1 The eastern Australian gas market is changing

The eastern Australian gas market is currently undergoing a period of rapid growth and transformation as it becomes the last of Australia's three geographically distinct gas markets to become linked to international markets. For the first time, domestic gas users on the east coast will be exposed to the influences of dynamics and prices in the Asia-Pacific market.

An increase in proven and probable reserves of gas, primarily derived from coal seams, has been a catalyst for the development of export capacity in the eastern Australian gas market. In the past decade, the proven and probable gas reserves in the Surat-Bowen basins in Queensland — where exploration for coal seam gas began in the 1980s — have grown roughly tenfold (DNRM 2015a). The liquefied natural gas (LNG) projects coming online in Gladstone, Queensland are the first to rely mainly on coal seam gas.

In turn, the structural adjustment associated with changes in the eastern Australian gas market currently underway has created, or exacerbated, a number of issues within the eastern Australian market.

These issues include: the implications, for domestic users, of the opening of export markets; the economic, environmental and social effects of gas production (especially from coal seams); and concerns about investment in and allocation of gas transmission pipeline capacity.

There has been a lot of recent commentary on the above issues, but some of the debate and the policy responses so far have not been framed in an economic context.

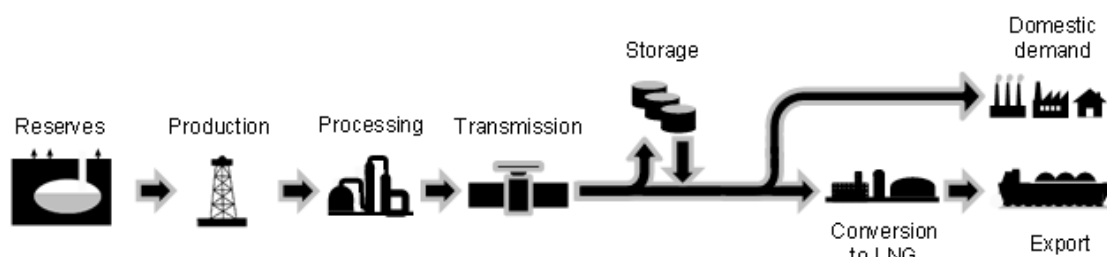
In this research project, the Commission has sought to provide an economic perspective on selected policy issues. The project focuses on the eastern Australian gas market but, as is the approach for all its work, the Commission examined the issues and evaluated policy proposals on the basis of whether they would be expected to improve the wellbeing of the community as a whole.

1.2 Analytical approach

In this report, the Commission has examined issues relating to different stages of the gas supply chain in the eastern Australian gas market, against the backdrop of integration with the Asia-Pacific market. The stages of the supply chain considered include exploration,

production, processing and transmission (figure 1.1). The Commission’s analysis has also considered the role of government in the market, and examined whether there are barriers to efficiency that would be amenable to policy reform.

Figure 1.1 **Selected stages of the gas supply chain^a**



^a Storage can occur either after transmission or prior to transmission.

One of the key aspects of the economic efficiency framework is the consideration of what barriers are preventing the efficient allocation of resources in gas markets. The other critical element of the economic efficiency framework is the application of cost-benefit principles. These principles apply to policy and market changes alike — a market change that makes some groups worse off, but others better off is a more efficient allocation of resources provided the gains exceed the losses.

The Commission’s model of the eastern Australian gas market

As part of the project, the Commission has developed a partial equilibrium economic model of the eastern Australian gas market (box 1.1). The model was used to complement the Commission’s analysis through illustrative examples of hypothetical policy scenarios. The model structure, data, assumptions and details of the policy scenarios are documented in appendix B (available online).

1.3 Conduct of the project

This research project was initiated by the Commission in September 2014. Following the commencement of the project, the Commission undertook consultation with a range of organisations and individuals, including representatives from gas companies, energy users, regulators, and government departments and agencies (appendix A).

The consultation process included a modelling workshop, held in Melbourne on 4 February 2015, to enable the Commission to receive feedback from stakeholders on

aspects of its model of the eastern Australian gas market. A separate meeting with gas users was held on the same day.

The report was released on 31 March 2015.

Box 1.1 Commission modelling of the eastern Australian gas market

The Commission has developed a partial equilibrium model that seeks to capture the underlying economic fundamentals of the eastern Australian gas market. The model is used to examine the effects of linking with the Asia–Pacific market, as well as selected policy issues, such as CSG moratoria and the effects of a domestic gas reservation policy. To test the sensitivity of model results, three different scenarios were estimated based on different estimates for LNG prices: a ‘low LNG price’ scenario, a ‘central LNG price’ scenario and a ‘high LNG price’ scenario.

The supply and demand sides of the market were represented in the model. Gas production, processing, transmission, storage and LNG conversion were modelled as separate activities in the supply chain. Demand for gas was disaggregated into demand from electricity generators, industry and mass market users. Exploration, distribution and retail were not explicitly modelled.

The geographical detail of the model captured key transmission pipelines linking major supply basins and demand centres in the eastern Australian gas market. Supply basins and demand centres were represented by ‘nodes’ in the model. Each supply basin contained up to ten fields, with production from each field limited by estimated gas reserves recoverable from that field.

The model was not designed to forecast prices, does not capture the full engineering detail of the gas market, and makes a number of simplifying assumptions about the structure of the market. Nevertheless, it provides a useful illustration of some of the mechanisms at play.

2 Framework for analysis

Economic analysis typically assesses the performance of markets compared to an ideal free of distortions. Few, if any, real-world markets conform to this ideal. Nevertheless, markets tend to perform well when they possess certain characteristics that facilitate an efficient allocation of resources. Markets require legal and institutional frameworks in which to operate, and all are accordingly regulated by governments in some way. The role of policy reform is to improve the functioning of markets, thereby helping to ensure that resources are allocated more efficiently. Importantly, intervention itself entails costs that must be outweighed by the benefits of policy change.

2.1 Characteristics of a well-functioning market

There are a number of market features that create an environment conducive to an efficient allocation of resources — discussed below.

Property rights bestow the right to use a resource, exclude others from its use, and usually also involve the ability to transfer that right, should the holder wish to do so. Well-defined property rights, combined with a sound regulatory framework that underpins their enforcement, help to ensure that decisions about resource allocation reflect their true economic and social value, and make clear the delineation of costs and benefits for market participants.

Sometimes, the actions of market participants will have effects on parties that are not part of the transaction — these effects are known as externalities, or ‘spillovers’. Provided the benefits of intervention exceed the costs, policies to address externalities can include defining and assigning property rights, using taxes or subsidies, or the introduction of some other form of regulation.

Competition is not an end in itself but plays a crucial role in promoting economic efficiency and enhancing community welfare. It can provide companies with greater incentives to innovate, reduce their costs and improve the quality of their goods and services. This leads to greater choice, better goods and services and/or lower prices for consumers. More broadly, competition helps society to generate the greatest value from its scarce resources over time, and achieve higher real household incomes and living standards (PC 2014c).

Conversely, markets characterised by the exercise of enduring market power would fail to attain the best outcomes for the community. In such markets, individual companies have some control over prices and can increase their profit by restricting output below optimal

levels over time. They are also subject to less pressure (compared to companies in competitive markets) to reduce production costs, and may have less incentive to innovate and to improve the quality of their goods or services.

While a competitive market generally consists of many buyers and producers dealing in an homogenous product, many markets function well without strictly satisfying those conditions of ‘effective competition’ may result in the best practically achievable market outcomes, and constrain any market power.

Access to sufficient information allows buyers and sellers to make decisions about resource use, while being aware of the true costs and benefits of their actions.

The transaction costs — the costs to participants of using markets — also need to be low enough to allow buyers and sellers to exchange goods and services. Prohibitive transaction costs (such as time and expense necessary to acquire information, and the costs involved in enforcing contracts) can impede trade altogether and prevent mutually advantageous trades from taking place.

Efficiency and equity

The above characteristics underpin the efficient operation of a market. They help to ensure outcomes where:

- resources are allocated to the uses in which they are most highly valued: for any good or service, this occurs when the marginal benefit (price) is equal to the marginal cost (including social costs that accrue in the course of production) (allocative efficiency)
- production is undertaken at the lowest possible cost, including broader environmental and social costs incurred during production (productive efficiency)
- incentives are in place to maintain productive and allocative efficiency over time, as changes in technology, consumer preferences and the price of inputs occur — investments should only take place when their total expected benefits exceed their full economic costs (dynamic efficiency).

An increase in economic efficiency improves overall community wellbeing (PC 2013d). Achieving market efficiency, however, does not mean that outcomes are geared to favour certain segments of the community, regardless of their effect on others.

Many calls for intervention in markets are associated with notions of fairness, or equity. Considerations of equity can be regarded as pertaining to ‘intragenerational equity’ or ‘intergenerational equity’. The latter notion is concerned with the fairness of the allocation of resources across generations — depletion of current natural gas reserves, for example, reduces the ability of future generations to utilise those reserves. Equity considerations are at least partly subjective, and therefore, involve more complex deliberations than assessing whether a particular policy action will enhance market efficiency or be detrimental to it.

2.2 Putting issues in gas markets into an economic context

Property rights and regulation

The design and allocation of property rights, and the imposition of regulations to address externalities, are important issues across the gas supply chain. For example, the allocation by governments of property rights to gas industry participants with no legal rights of veto has contributed to community concerns about the health and environmental risks of gas exploration and production.

Unconventional gas exploration and production is currently meeting substantial community resistance, due to the disruption and other costs it imposes on the current owners of the land and the costs arising from social and environmental externalities it could inflict on the community (chapter 5). The constraints that apply to property rights will also tend to affect their valuation — property that confers additional privileges on its holder will be valued more highly than identical property which does not, all else equal.

In gas transmission, the design of property rights influences how pipeline capacity is allocated, and therefore whether capacity is allocated to the uses in which it is most highly valued. Property rights in transmission can also affect incentives for investment (chapter 6), and hence, have consequences for dynamic efficiency.

Market structure and competition

Many elements of the gas supply chain in Australia have a market structure in which there are a small number of companies. In some markets, overall costs are lower with a structure where there are a small number of companies that are relatively large, instead of a large number of smaller companies competing against each other. For example, natural monopoly industries involve high and lumpy fixed costs that need to be amortised over production. In such industries, it is more productively efficient to have one producer than several, as this allows production to occur at its lowest cost.

However, even where there are a small number of companies or a natural monopoly, there may be constraints to the exercise of any market power. These constraints include the availability of substitute goods or services, such as alternative energy sources or energy suppliers, and the ability of buyers to exercise countervailing power. The threat of entry to a market can also prevent participants from exercising any market power if it exists. For example, producers that raised prices above competitive levels would find that new entrants are attracted by the profits made by incumbents, and enter the market, placing downward pressure on prices. A key issue is whether there are unnecessary barriers that prevent new market entrants.

These issues are discussed in the context of gas production, transmission and processing in chapters 4, 6 and 7.

Poor information and high transaction costs

In Australia, markets for the transmission of gas tend to be characterised by scarce information and limited transparency. This partly reflects the predominance of bespoke and non-transparent bilateral contracts for trading wholesale gas and transmission capacity in Australia's gas markets, and the relatively small number of buyers and sellers in these markets. Stakeholders have highlighted a lack of transparent information on the identity of pipeline capacity contract holders, pipeline usage rates, and the availability and price of secondary capacity. The higher transaction costs arising from a lack of transparent information in secondary pipeline capacity markets could be a potential barrier to entry and trading capacity in retail markets. There have been calls from some stakeholders for further regulatory intervention, as well as reforms to reduce transaction costs from trading capacity in secondary markets (chapter 6).

Rising gas prices as a basis for intervention

Many stakeholders recognise that one of the main causes of higher prices in the eastern Australian gas market is the newly-established linkage to the Asia-Pacific market (chapter 3). Gas users and other stakeholders have called for government intervention to assist industries affected by rising gas prices.

Some stakeholders have called for the stimulation of greater levels of exploration and production, such as through the imposition of strict 'use it or lose it' provisions on gas explorers and producers (chapter 4). Others have urged that the export of gas be constrained by reserving quantities of gas for domestic use in an effort to insulate Australian users from international forces and higher prices. Similar suggestions have included the introduction of a 'national interest test' for new or significantly expanded LNG activity (chapter 7).

Addressing equity objectives

Equity issues can arise in the context of resolving land use conflicts in gas production, as the current legal regimes and the growing demand for access to land by the gas industry challenge expectations of incumbent landholders and local communities about their property rights (chapter 5).

Extracting non-renewable resources also has intergenerational effects. Even when particular paths of gas investment and production are economically efficient, equity considerations may mean that it is preferable from the community's perspective not to develop gas resources. There are, however, costs involved with delaying efficient resource

development, particularly if the value that can be derived from those resources is diminished by the advent of new technology that allows a degree of substitution away from gas and toward other energy sources. There would also be a cost to current generations, in the form of the foregone use of the resource and royalty and taxation revenue to the Australian governments; this revenue could have subsequently been invested in a range of areas including physical or human capital.

It is, however beyond the scope of this report for the Commission to present a view on what it considers to be an equitable distribution of resources, either across the economy, or over time, as perspectives on equity are subjective, and likely to differ from person to person. Ultimately, decisions about such equity issues, insofar as they are related to policy decisions, are the responsibility of elected governments. The Commission has made observations where some actual or proposed policies may have unintended implications for equity. More broadly, transparency is a sound principle for policymakers and there should be a thorough analysis of the consequences for efficiency of a policy justified on equity grounds.

3 Overview of Australian gas markets

Key points

- In 2012-13, the Australian oil and gas industry generated over \$32 billion in value added and directly employed over 20 000 people.
- Within the eastern Australian gas market, a small number of large producers (often in the form of consortia) hold exploration and production licenses and account for the bulk of gas production.
- In 2012-13, about two-thirds of all gas use in the eastern Australian gas market was for manufacturing and electricity generation. Residential use accounted for roughly 20 per cent of consumption.
- A significant and rapid transition is currently underway in the eastern Australian gas market, as a link is established to the Asia–Pacific market.
 - Some projections suggest that total demand in the eastern Australian gas market could increase roughly threefold to more than 2000 petajoules by 2018, with more than two-thirds of this consisting of demand for liquefied natural gas (LNG) exports.
- The linkage of the eastern Australian gas market and the Asia-Pacific gas market represents an opportunity for the Australian community overall to earn a higher return from extracting its substantial non-renewable resources, resulting in an overall net benefit to the community.
- Integration with the Asia-Pacific region is creating significant disruption for eastern market participants, and will lead to material costs for some gas users.
 - Some large gas users have reported difficulty securing gas contracts, and indicated they may be forced to reduce output or exit Australian manufacturing altogether.
 - Those who use gas as a feedstock or for industrial processes to produce chemicals, materials or plastic products have limited capacity to switch to alternative inputs.

3.1 Australian gas markets

Economic context of gas in Australia

The past decade has seen a significant increase in the demand for Australian mineral and energy resources, including gas. The oil and gas sector in Australia has grown markedly, both in terms of its industry value added and employment (table 3.1).

Table 3.1 Broad economic characteristics of oil and gas extraction in Australia^a

	2003-04	2013-14	Percentage change
Gross value added (\$ billion, 2012-13)	18.1	28.9	59.7
Direct employment	6 200	24 200	290.3
Percentage of total employment	0.07	0.21	200
Exports (\$ billion)	9.5	30.8	224.2
Percentage of total goods exports	8.7	11.3	29.9

^a Data for gross value added and direct employment are jointly reported for the oil and gas industries.

Sources: ABS (*Australian System of National Accounts*, Cat. no. 5204.0); ABS (*International Trade in Goods and Services*, Australia, Cat. no. 5368.0); ABS (*Labour Force, Australia, Detailed, Quarterly*, Cat. no. 6291.0.55.003).

In 2012-13, natural gas (methane)¹ (box 3.1) and liquefied petroleum gas (LPG, propane) accounted for roughly 13 per cent of all Australian energy production by fuel type, and was used to generate about 20 per cent of Australia's electricity. In that year, oil and gas accounted for more than 12 per cent of Australia's energy exports (by volume), behind coal (roughly 60 per cent) and uranium (approximately 25 per cent) (BREE 2014a).

Box 3.1 Measuring gas

Gas production and consumption may be measured in terms of volume, mass or embodied energy (calorific value). Gas volume (such as cubic metres) and mass (such as kilograms) do not account for the energy content of the natural gas which varies because of the composition of natural gas (principally methane, but depending on the source of the gas other elements and compounds such as carbon dioxide, nitrogen, ethane and propane). In general, the more carbon atoms in a given volume of natural gas, the higher will be its calorific value.

When measuring the volume of natural gas, the ambient temperature and pressure of the gas is calculated against a standardised pressure and temperature before being converted to an embodied energy measure typically used to describe production and consumption.

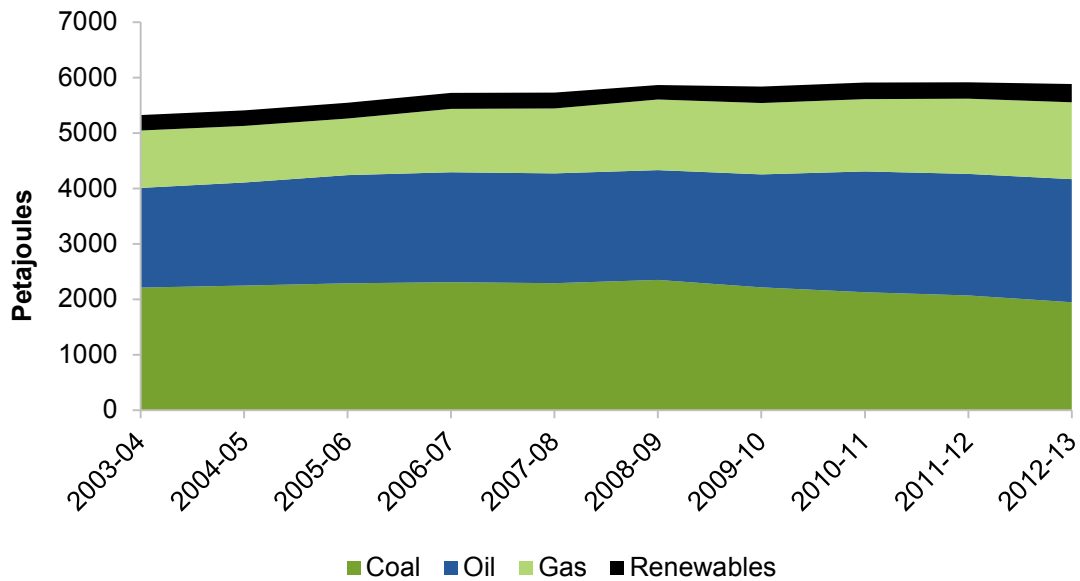
For residential use, natural gas is typically charged per unit of megajoule (MJ), a measure of energy. For large quantities of natural gas traded, a petajoule (PJ) is used. A PJ is equal to 1 thousand terajoules, 1 million gigajoules (GJ), 1 billion megajoules, or 10^{15} joules. Where the Commission has converted original data from tonnes into PJ, it has used the conversion rate: 1 million tonnes = 54.4 PJ.

Sources: APPEA (2014e); BREE (2014c); IEA (2005).

¹ Natural gas is mainly methane (CH₄), but its exact composition depends on the source and may include a number of other elements and compounds. Compressed natural gas (CNG) is stored in high-pressure tanks (20 to 25 megapascals). Liquefied natural gas (LNG) is a cryogenic liquid cooled to between minus 120 and minus 170 degrees Celcius. CNG compresses natural gas to a volume less than 1 per cent of its volume at standard atmospheric pressure. LNG compresses natural gas to about 1/600th of its volume at standard atmospheric pressure (AFS nd; APPEA 2014e).

In Australia, gas consumption has grown faster than consumption of other energy sources over the past decade (figure 3.1). The share of gas in energy consumption has increased steadily from less than 10 per cent in the 1970s to about 25 per cent today (BREE 2014a).

Figure 3.1 Australian energy consumption
2003-04 to 2012-13



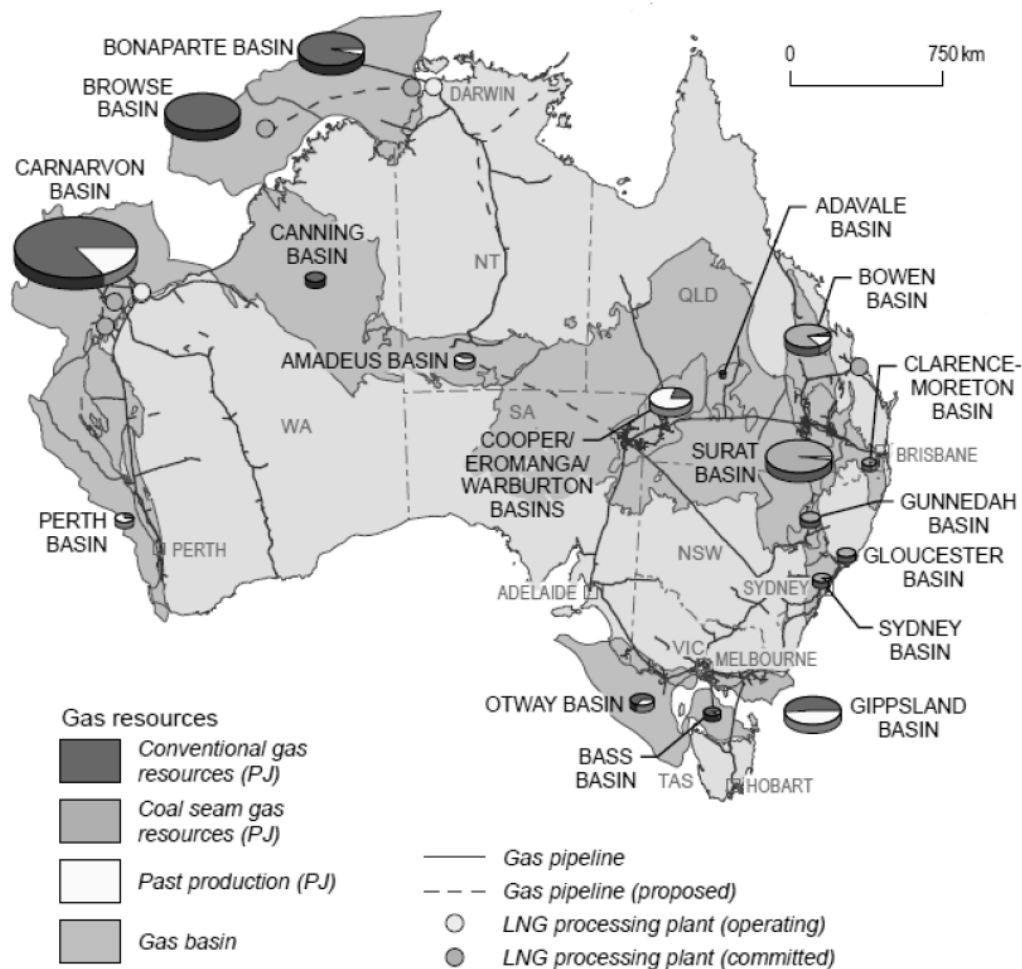
Source: BREE (2014a).

Geography of Australian gas markets

Australia has three geographically distinct gas markets:

- the eastern Australian gas market, which connects New South Wales, Queensland, Victoria, South Australia, Tasmania and the Australian Capital Territory
- the western market (Western Australia)
- the northern market (the Northern Territory) (figure 3.2).

Figure 3.2 Australia's major gas resources and infrastructure^a



^a Excludes the Joint Petroleum Development Area in the Timor Sea.

Source: BREE (2014d).

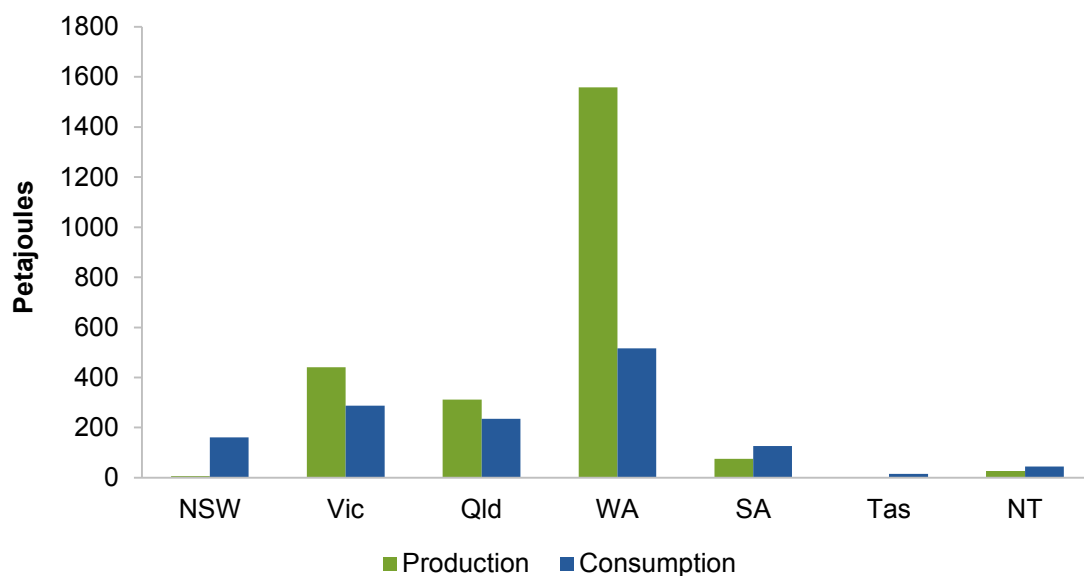
The three markets are not connected by physical infrastructure, although there have been proposals to connect them. For example, in recent months, a proposed pipeline linking the Northern Territory and the eastern Australian gas market has been publicly discussed, and the Northern Territory and New South Wales Governments signed a Memorandum of Understanding in November 2014 regarding its development (Northern Territory Government 2014).

Western Australia is the largest producer of gas in Australia

The location and type of users, climatic variability, the availability of alternative energy supplies, and the distribution of geological resources, all give rise to differing patterns of gas production and consumption across Australia.

In 2012-13, the majority of Australian gas production by volume (roughly 65 per cent) occurred in Western Australia, and that state also accounted for over 35 per cent of Australian gas consumption (BREE 2014a). Western Australia typically produces a large surplus of gas which is exported as LNG. Queensland and Victoria are also large producers and consumers of gas (figure 3.3). These states exported surplus gas to other states through interstate pipelines. New South Wales and Tasmania consumed gas imported from other states through interstate pipelines.

Figure 3.3 Production and consumption of gas by state and territory
2012-13



Source: BREE (2014a).

The production and consumption patterns in the eastern states are currently undergoing a substantial transformation following the development of infrastructure in Queensland to export gas in the form of LNG to the Asia-Pacific market (discussed further in section 3.2).

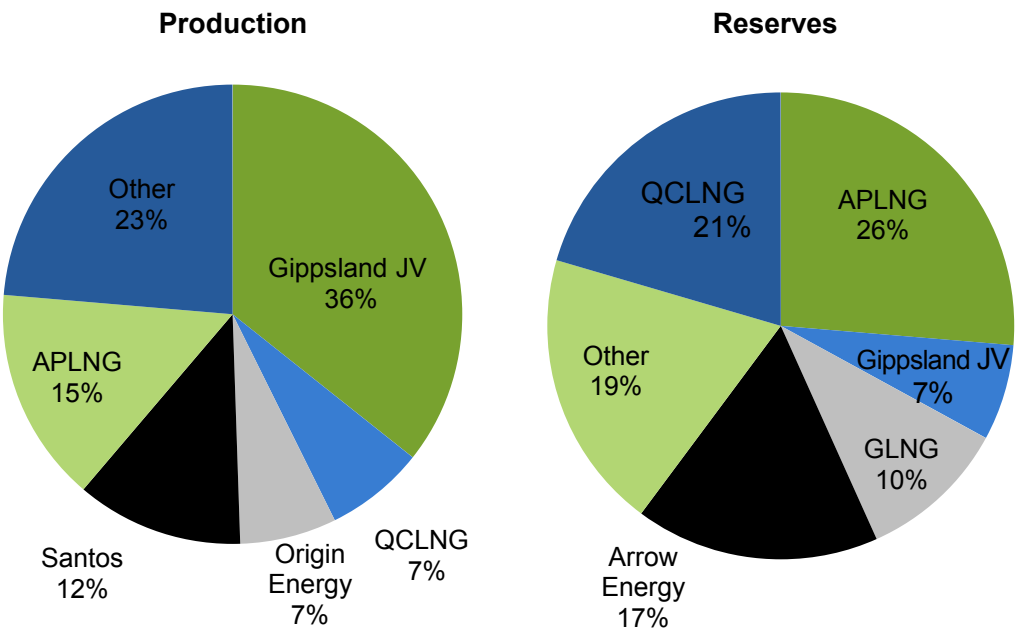
Structure of the eastern Australian gas market

Which gas companies are active in the eastern Australian gas market?

The vast majority of gas production in the eastern Australian gas market occurs in a small number of basins. In 2013-14, the Gippsland and Surat-Bowen basins each accounted for about one-third of production, and the Otway and Cooper basins accounted for roughly a further 15 per cent each (AER 2014). Since 2002-03, production has increased in the Surat-Bowen basins (primarily attributable to coal seam gas (CSG) field development) and the Otway basin, while production has declined in the Cooper basin.

A small number of large producers (often in the form of consortia) account for the bulk of gas production and reserves (figure 3.4).

Figure 3.4 **Eastern Australian gas market production and reserves by company^{a, b}**
2013



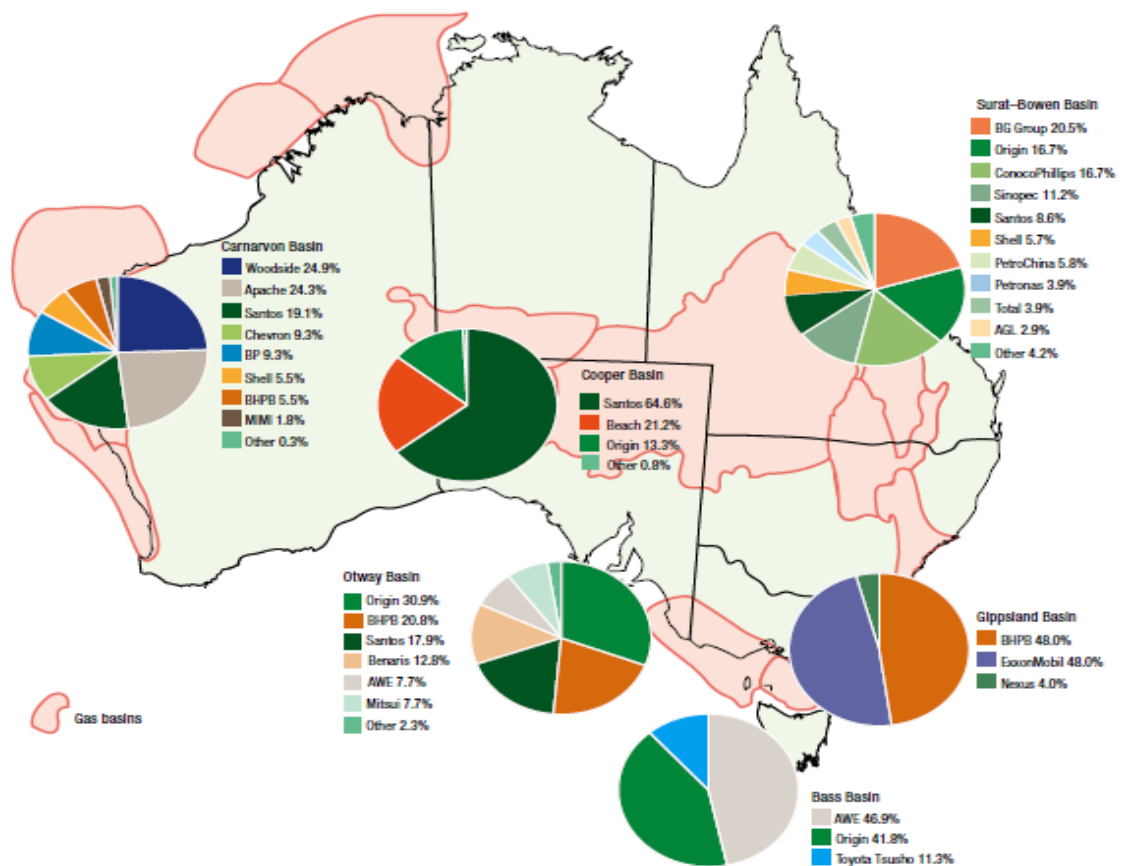
^a Entries for Origin Energy and Santos exclude interests in other specific ventures listed. ^b Totals may not sum to 100 due to rounding.

Source: BREE (2014b).

The number of producers differs across basins (figure 3.5). For example, a single joint venture between BHP Billiton and Esso Australia has the most significant presence in the

Gippsland basin, which accounts for 10 per cent of eastern Australia's 2P gas reserves². By contrast, more than ten companies have a share of production in the Surat-Bowen basins, in which about 80 per cent of the eastern Australian market's 2P reserves are located (AER 2014).

Figure 3.5 **Market shares in Australian gas production, by basin^a**
2012-13



^a Excludes the Joint Petroleum Development Area in the Timor Sea.

Source: AER (2013a).

Processing plants are usually located near gas fields. Owners of processing plants often have interests in gas production and other parts of the supply chain, including retail. In some basins, there can be one or several large processing plants. In other basins, typically those where fields are geographically dispersed and where gas is produced from CSG reserves, there are several processing plants. For example, in the Gippsland basin, the Longford Gas Plant, the largest gas processing facility in Australia, is owned by Esso and

² 1P reserves are proved reserves. 2P reserves = 1P + probable gas reserves. 3P = 2P + possible gas reserves. There are also three categories used to describe contingent resources — that is, resources that are not yet regarded as commercially recoverable. 1C contingent resources are a low estimate of contingent resources, 2C a medium estimate and 3C a high estimate.

BHP Billiton (50 per cent each). By contrast, in the Surat-Bowen basins, there are many processing facilities. Owners include APA Group, Arrow Energy (a consortia of Shell and PetroChina), Australia Pacific LNG, BG Group (which has a stake in the Queensland Curtis LNG project), Santos and Origin Energy.

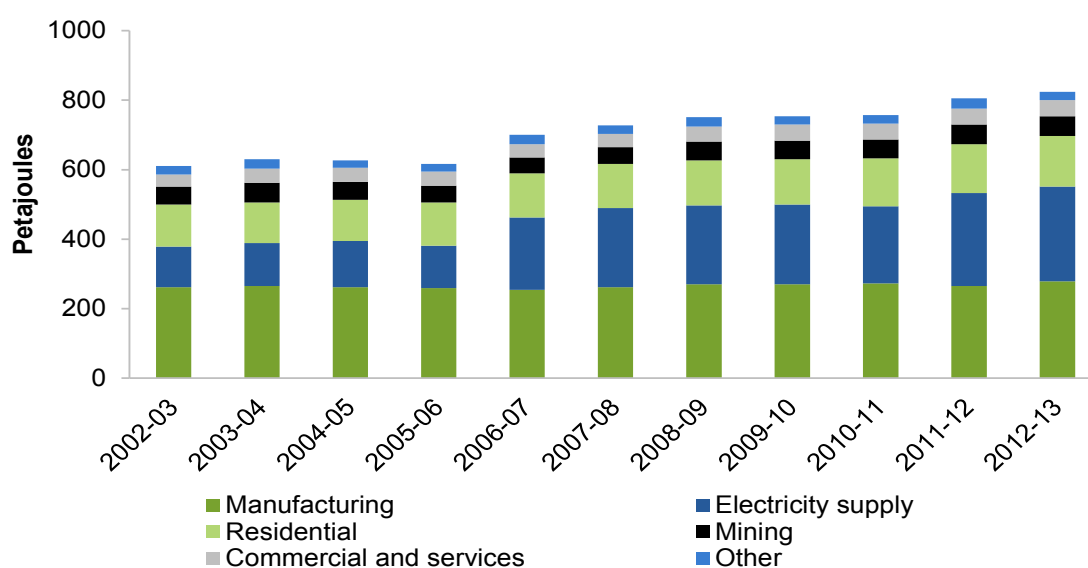
A number of private companies own transmission pipelines in the eastern Australian gas market. APA Group is the principal owner of gas transmission assets including the Moomba to Sydney Pipeline, the Roma to Brisbane Pipeline and the Victorian Declared Transmission System. Jemena owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline. There are also several smaller players in the market (AER 2013a).

Who are the consumers of gas?

Demand for gas in the eastern Australian gas market is from residential and commercial users, industrial users (including manufacturing industries and the mining industry), and electricity generators.

In 2012-13, manufacturing industries and electricity generation each accounted for about one-third of use in the eastern Australian gas market, and residential consumption accounted for just under 20 per cent of use (figure 3.6). Essential Energy (2015) estimate that (in New South Wales) about 60 per cent of residential gas use is for space heating, over 30 per cent for water heating, and less than 10 per cent for cooking.

Figure 3.6 Gas use in the eastern Australian market
2002-03 to 2012-13



Source: BREE (2014a).

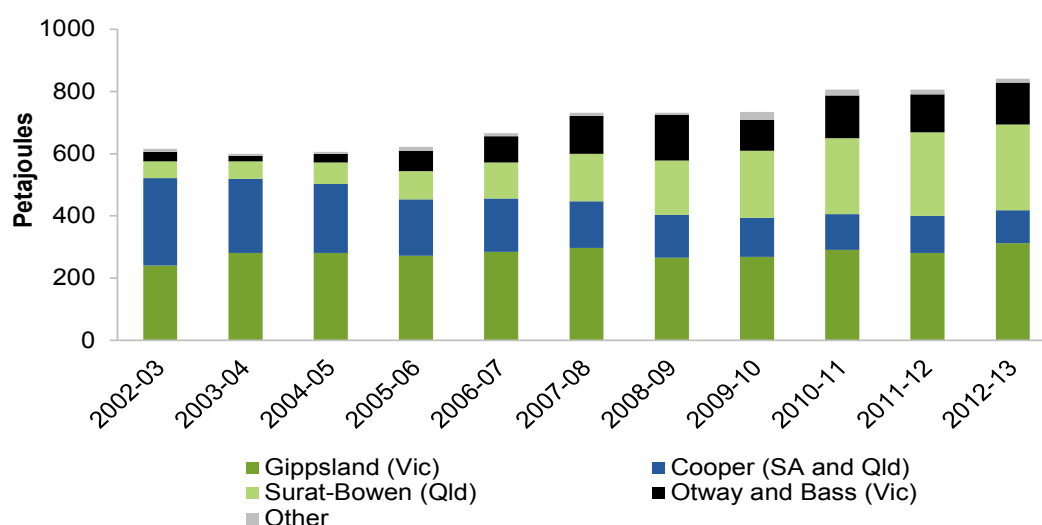
Industrial demand is characterised by a small number of gas-intensive industries including aluminium smelting, brick and cement production, chemical production and mining. For some industries, gas cannot be substituted easily, or at all, with other energy sources or products. For example, in some plastic and chemical production, gas is used as a feedstock rather than a source of energy. In these applications, natural gas is converted via a catalyst into chemicals that are used in the manufacture of other products (AIP nd). For instance, ammonia and ammonium nitrate, in conjunction with natural gas, are used to manufacture goods such as fertiliser and explosives. Similarly, polyethylene is used for products such as piping and grain bunkers.

Manufacturing plants that require gas as a feedstock typically run continuously, meaning that they have limited ability to tolerate fluctuations in, or interruptions to, gas supply. The use of gas as a feedstock can be significant — the Plastics and Chemicals Industry Association estimated that such use accounted for approximately 25 per cent of gas consumed in New South Wales (Plastics and Chemicals Industry Association, pers. comm., 6 March 2015).

3.2 Growth in LNG exports and linkage to the Asia-Pacific

In recent years, the extraction of CSG combined with the development of an LNG export industry in Queensland has linked the eastern Australian gas market to the Asia-Pacific market. This process has driven significant and rapid change, with adjustments in prices and consumption occurring alongside growth in gas production (figure 3.7).

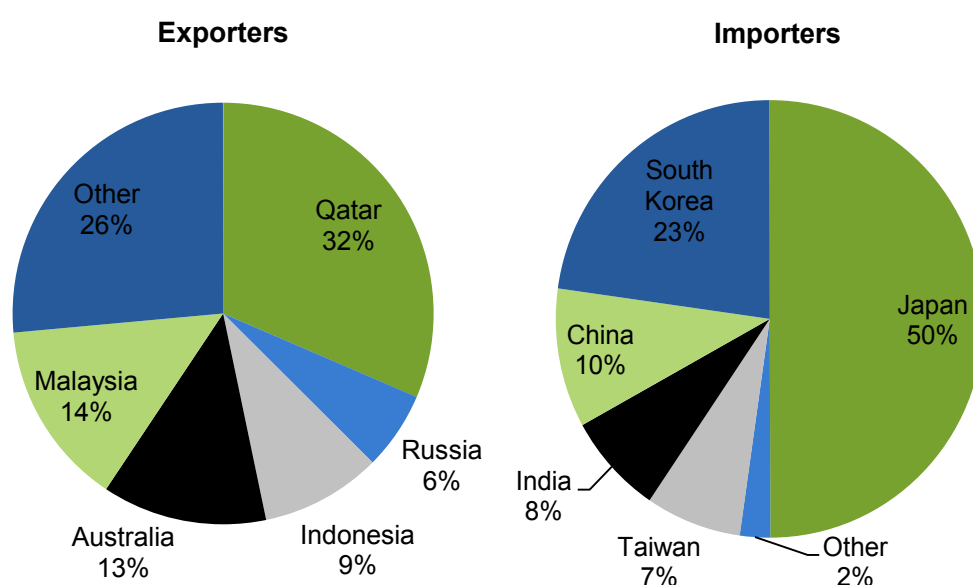
Figure 3.7 Production in the eastern Australian gas market
2002-03 to 2012-13



Source: BREE (2014a).

A significant share of global trade in LNG occurs in the Asia-Pacific market; in 2013, about three-quarters of all world imports of LNG were consumed in the Asia-Pacific market. The single largest exporter of LNG to the Asia-Pacific market in 2013 was Qatar, accounting for about one-third of all exports to that market. Although Australia was the third biggest single exporter of LNG, it accounted for a significantly smaller share of the market, at 13 per cent. Japan was the dominant LNG importer in the region by a significant margin (figure 3.8). Of Australia's exports of LNG to the Asia-Pacific in 2013, the vast majority (81 per cent) was destined for Japan, while the balance was mainly accounted for by China (16 per cent) (BP 2014).

Figure 3.8 **LNG exporters and importers in the Asia-Pacific market**
2013



Source: BP (2014).

Investment in export capacity in the eastern Australian gas market

Prior to the first shipment of LNG from Gladstone in January 2015, there were three LNG liquefaction plants operating in Australia with a total capacity of over 1300 PJ³:

- the Karratha Gas Plant which takes gas from the North West Shelf Venture (Carnarvon basin, Western Australia) (capacity of approximately 887 PJ)
- Pluto LNG which takes gas from the Pluto Field (Carnarvon basin, WA) (capacity of roughly 234 PJ)

³ Original data reported in millions of tonnes per annum have been converted to PJ using the rate: one million tonnes = 54.4 PJ, as reported by BREE (2014c).

- Darwin LNG which takes gas from the Joint Petroleum Development Area in the Timor Sea (capacity of about 200 PJ) (APPEA 2014b; IEA 2014).

In recent years, there has been a tenfold increase in 2P CSG reserves in the Surat-Bowen basins — from less than 4000 PJ in 2005 to about 42 000 PJ at June 2014 (DNRM 2015a). This increase in reserves, together with expectations of higher gas prices and new sources of demand, have been catalysts for the development of export capacity in the eastern market. There have been construction delays and cost blowouts affecting some LNG projects.

Each LNG project at Gladstone has two committed LNG trains — for a total capacity of over 1300 PJ (table 3.2). A fourth project at Gladstone — Arrow Energy's LNG project, a 50/50 joint venture between Shell and Petrochina with a 435 PJ per annum capacity — was proposed, but in January 2015, Shell announced that the project was 'off the table' (Core Energy Group 2013b; Macdonald-Smith 2015; van Beurden and Henry 2015, p. 11; Wilkinson 2015). Although the export project will not proceed, Shell has stated that the development of wells in the Surat-Bowen basins will continue (ABC 2015).

The level of future production depends on many factors, including LNG prices, which are linked to world oil prices, and domestic production costs.

Table 3.2 LNG projects at Gladstone

	<i>Ownership</i>	<i>Share per cent</i>	<i>Operator</i>	<i>Train/capacity^a</i>	<i>Actual/expected operating date</i>
Australia Pacific LNG (APLNG)	Origin Energy	37.50	Conoco-Phillips	Train 1: 245 PJ	Second half 2015
	Conoco-Phillips	37.50		Train 2: 245 PJ	First half 2016
	Sinopec	25.00			
Gladstone LNG (GLNG)	Santos	30.00	Santos	Train 1: 212 PJ	First half 2015
	Petronas	27.50		Train 2: 212 PJ	Second half 2015
	Total	27.50			
	Kogas	15.00			
Queensland Curtis LNG (QCLNG)	BG Group	73.75	BG Group	Train 1: 231 PJ	January 2015
	CNOOC	25.00		Train 2: 231 PJ	Second half 2015
	Tokyo Gas	1.25			

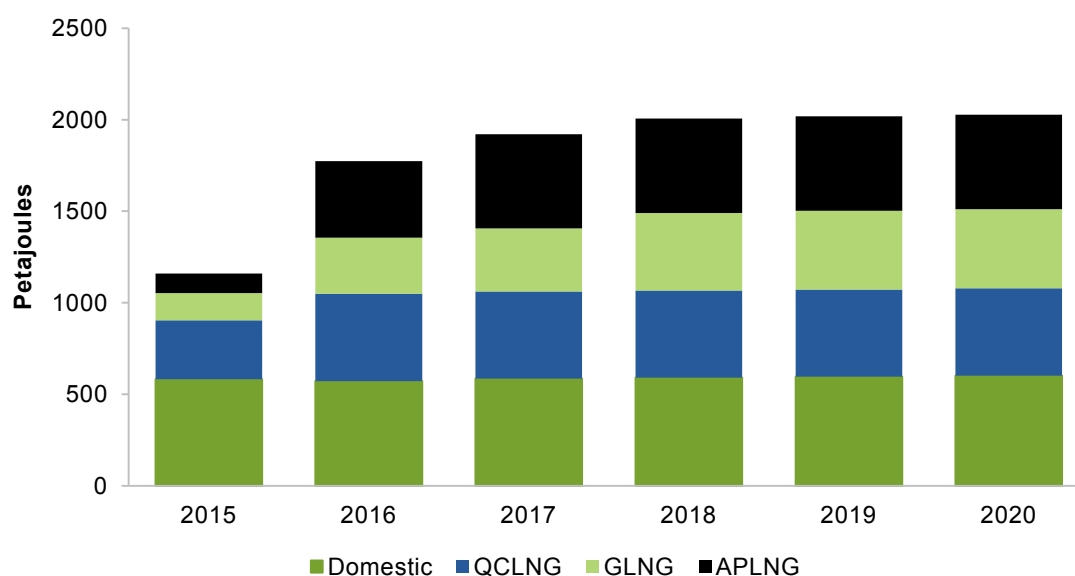
^a Original data reported in millions of tonnes per annum have been converted to PJ using the rate: one million tonnes = 54.4 PJ.

Source: Adapted from BREE (2014c; 2014d).

Effects of linkage to the Asia–Pacific on demand

Australian gas demand in the eastern market is projected by the Australian Energy Market Operator to remain relatively stable through to 2020, while demand for gas from LNG projects is expected to increase rapidly (AEMO 2014b). Total demand (domestic and for export) in the eastern market is projected to increase roughly threefold over the next 3–5 years, to over 2000 PJ per annum (figure 3.9).

Figure 3.9 **Projected demand in the eastern Australian gas market**
2015–2020



Source: AEMO (2014b).

Given that overseas demand is projected to increase dramatically, there have been concerns about whether LNG projects have sufficient supply to meet their export contract commitments, with commitments effectively locked in the short term (although the cancelling of the Arrow Energy's LNG export project might free up additional supply). The Australian Industry Group (AIG) stated that:

... the gas market is very tight at present, as the LNG exporters lock up any supply they can find in order to meet their commitments and make up for slower production growth than anticipated. (2013, p. 6)

The Australian Energy Market Operator (AEMO) has projected potential shortfalls in gas supply over the medium term, with shortfalls projected to occur in peak periods (four winter days) in New South Wales and throughout the year in Queensland in 2020 (AEMO 2014b). Another issue related to gas supply is the performance and cost of CSG wells, and the number of wells that will be required to meet demand when all three LNG projects are operational.

Estimates of reserves and resources change over time, due to depletion, new discoveries and changing commercial viability, and should therefore be interpreted and used with some caution. Core Energy Group (2013a) have used publicly available data sources to estimate that, as at 31 December 2012, almost 90 per cent of 2P reserves in eastern Australia were in the form of CSG resources, with CSG also accounting for a significant share of 3P/2C reserves and resources (table 3.3). In New South Wales, a moratorium currently applies to new CSG exploration licences and on CSG production in water catchments. In Victoria, a moratorium applies to all hydraulic fracturing and new onshore exploration licences (chapter 5).

Table 3.3 Eastern Australian gas resources by type
2012

<i>Resource type</i>	<i>Total reported reserves and resources</i>					
	2P reserves		3P/2C reserves and resources		Prospective resources	
	PJ	%	PJ	%	PJ	%
Conventional	7 093	13	5 284	7	21 902	6
CSG	46 131	87	67 995	86	142 323	42
Unconventional	5	0	5 707	7	178 915	52
Total	53 229	100	78 986	100	343 140	100
<i>Selected basins</i>						
Bass	268	0.5	291	0.4	0	0
Clarence Morton	445	0.8	12 547	15.9	3 816	1.1
Cooper and Eromanga	1 948	3.7	6 951	8.8	193 376	56.3
Galilee	0	0	259	0.3	4 413	1.3
Gippsland	3 937	7.4	3 292	4.2	7 910	2.3
Gunnedah	1 426	2.7	4 961	6.3	48 684	14.2
Otway	756	1.4	329	0.4	11	0.0
Surat-Bowen	43344	81.4	47 724	60.4	27 155	7.9
Sydney	340	0.6	2 262	2.9	33 395	9.7

Source: Core Energy Group (2013a).

How will the linkage affect prices in the eastern Australian gas market?

In the eastern Australian gas market, long-term bilateral contracts have traditionally been the preferred means by which to trade gas. There are gas transportation agreements between pipeline operators and gas shippers, and gas supply agreements between gas producers and gas users (BREE 2014b). Due to commercial confidentiality clauses, the details of bilateral contracts (including terms and conditions, as well as pricing) are not

publicly available (and would be difficult to compare in any case due to their bespoke nature).

As noted by BREE:

These contractual arrangements usually contain a complex array of terms, conditions, and price linkages, but are opaque to third parties. Knowledge of contract terms and prices is largely based on informal mechanisms within the small gas trading community. (2014b, p. 16)

Long-term wholesale gas contracts have traditionally incorporated charges based on peak demand, multiplied by an escalator (usually the consumer price index) over the contract life, with price reviews every 3–5 years (BREE 2014d; Jacobs SKM 2014a). BREE observed that many gas supply agreements typically include the following terms and conditions:

- responsibility and obligations of parties
- annual gas quantities (including seasonal variations), monthly estimates of use/supply, and daily nomination details
- term of supply and supply arrangements, such as gas quality, permitted interruption and quantity variation conditions
- price review mechanisms and payment details and obligations
- details of the adequacy of 2P reserves
- contract termination and dispute resolution mechanisms
- confidentiality details and credit provisions. (BREE 2014b, p. 62)

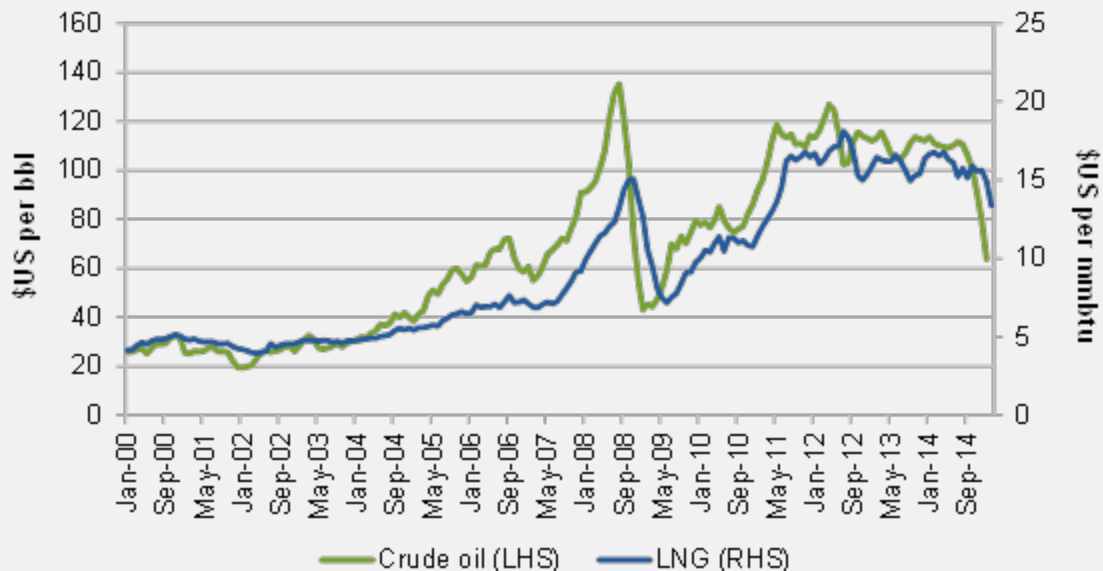
Long-term bilateral contracts are not the only means by which gas is traded in the eastern Australian gas market. Short-term trading markets operate in Adelaide, Brisbane and Sydney. In Victoria, there is a wholesale market that is managed by AEMO. Furthermore, a gas supply hub designed to facilitate wholesale trading was established in 2014 at Wallumbilla in Queensland, and operates on the basis of trades between gas producers and shippers. As a result of the various mechanisms by which gas can be bought and sold, there are a range of prices at which gas may be traded.

Pricing mechanisms in the Asia-Pacific gas market — where prices are explicitly linked to oil prices — differ from the historic eastern Australian gas market regime. The principal pricing model for contracts is the Japan Customs-cleared Crude or ‘Japan Customs-cleared Crude’ index (JCC) (box 3.2). Between 2011 and 2014, Jacobs SKM (2014a) observed that of nine new wholesale contracts negotiated in the eastern Australian gas market, at least three included oil-indexation mechanisms. Contract prices can depend on a range of other factors, such as contract size and duration, reliability of supply and the relationship between gas suppliers and their customers.

Box 3.2 Gas pricing in the Asia-Pacific market

Development of the Asia-Pacific market began in the 1970s, as Japan sought to diversify its energy supplies following increases in oil prices from 1973 (Jacobs 2011). At the time, crude oil was a competing fuel to gas, and hence a link to the crude oil price was introduced into Japanese LNG import contracts. In 1986, South Korea became an LNG importer, followed by Taiwan in 1990. By this time, the JCC pricing mechanism had been established, in which LNG prices were linked to the average price of crude oils imported into Japan (Rogers and Stern 2014).

Under this system, changes in the price per unit of LNG correspond to changes in the spot price of crude oil (see figure below). Because contracts are privately negotiated between buyers and sellers, the precise details of the relationships between variables is not known. Generally however, under the JCC pricing model, LNG is sold at a price that is a proportion of the JCC price (BREE 2014d). Contracts may include negotiated upper and lower caps for prices in order to reduce buyer and seller exposure to price fluctuations.



Sources: PAJ (2015); World Bank (2015b).

A commonly cited benefit of linking LNG prices to an oil price index is that oil is globally traded and cannot be easily manipulated by any particular seller nation. In addition, the oil price linkage may also provide a reference point, so that buyers are paying prices close to those of the next best alternative fuel (BREE 2014d). Although the JCC pricing mechanism has been in operation in the Asia-Pacific market for a number of years, its continued use has been questioned by some analysts, such as Rogers and Stern (2014). Concerns have been driven by fluctuations in oil prices since 2008, as well as increased demand for LNG in Japan since 2011. This has prompted discussions about alternative pricing mechanisms, such as the establishment of an Asian LNG hub (Rogers and Stern 2014). To date however, it is unclear whether a new price mechanism will be adopted, and if so, what form it will take.

Have gas prices been rising?

In recent years, some gas users have expressed concerns about rising gas prices. As noted above, prices in the eastern Australian gas market can vary from contract to contract (in part, reflecting differences in other contract conditions) and are not publicly available. It is, therefore, difficult to draw conclusions about long-term prices.

The Australian Industry Group (AIG 2013) undertook a survey of business gas users in the eastern market and found that half of businesses surveyed were looking for new gas contracts. Among those businesses, 10 per cent reported they could not get an offer at all, one-third reported they could not get a ‘serious’ offer and one-quarter reported they could only get an offer from one supplier. AIG noted that they expected gas prices to rise from a historic average of \$3–4 per GJ and found that:

- businesses seeking relatively short-term contracts beginning in 2013 received an average offer of \$5.12 per GJ
- businesses seeking later starting or longer-term contracts received an average offer of \$8.72 per GJ (AIG 2013).

Jacobs SKM (2014a) estimated contract prices for users in the eastern Australian gas market that had been agreed since 2011, largely relying on statements by equity market analysts and journalists. Estimated new contract prices ranged from \$5.50–10 per GJ, compared with contract prices averaging between \$3.50 per GJ and \$5.00 per GJ in 2010. Prices for gas in southern states, where gas was sourced from the Gippsland basin, were generally lower than prices in Queensland.

More data are available for short-term prices in markets in capital cities, which have been volatile in recent years (figure 3.10). Declines in short-term gas prices since 2012–13 — in Brisbane in particular — are largely due to the production of ‘ramp gas’ for LNG projects combined with flat Australian demand (BREE 2014d). Gas production from CSG wells cannot be scaled down or turned off as easily as production from conventional wells, so there has been additional gas available as CSG production has commenced from fields that will later be used to serve export demand.

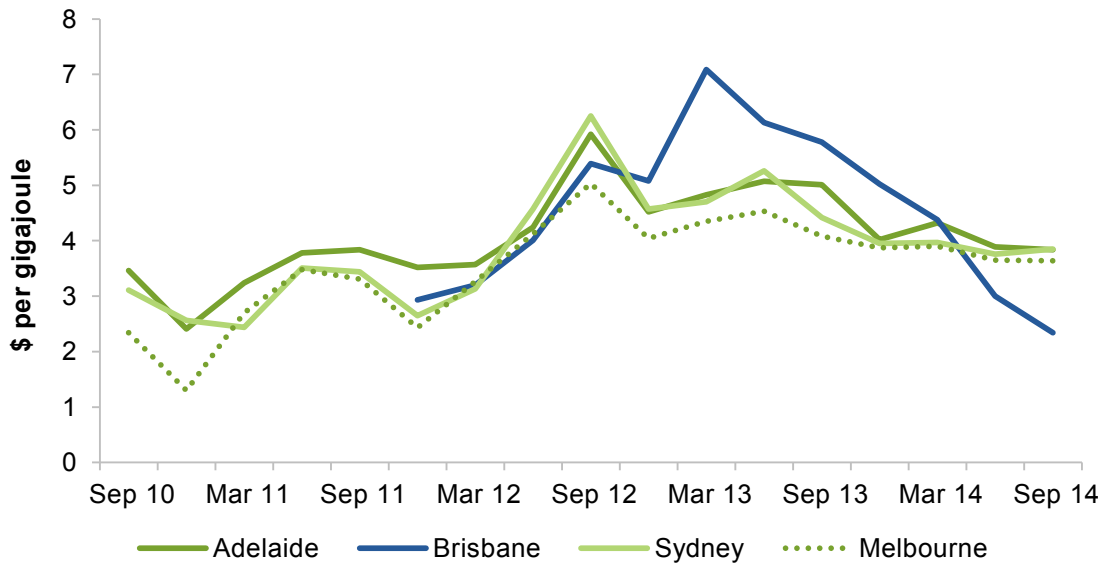
Will gas prices rise in coming years?

For gas producers, LNG export prices represent the opportunity cost of supplying gas to the eastern Australian gas market. Some analysts (for example, K Lowe Consulting 2013) have suggested that the linking of the eastern Australian gas market to the Asia–Pacific market will lead to eastern market prices converging to an ‘LNG netback price’ (that is, the Asia-Pacific LNG export price, less the long-run marginal cost of transport and liquefaction).

However, there are a number of influences that could cause the price in the eastern Australian gas market to diverge from the LNG netback price at any particular time

(box 3.3). For this reason, attempts to reverse engineer an estimate of the efficient prices in the eastern Australian gas market from LNG prices, or to determine whether there is a policy problem from any discrepancy, are problematic.

Figure 3.10 Short-term gas prices in the eastern Australian gas market^{a, b}
September 2010–September 2014, Quarterly average prices



^a Ex ante prices are used from the short-term trading markets in Adelaide, Brisbane and Sydney.

^b Prices for Melbourne are average daily weighted imbalance price (taken from the Declared Wholesale Gas Market).

Sources: AER (2015a, 2015b).

Nevertheless, international demand and supply forces will, via LNG export prices, exert a considerable influence on prices in the eastern Australian gas market. Sinclair Knight Mertz projected that prices for new contracts could increase by between 10–60 per cent from 2014 levels by 2020, depending largely on what happens in the Asia–Pacific market (SKM 2013b).

The Commission’s modelling of the eastern Australian gas market was used to illustrate some of the mechanisms at play (appendix B). As there is considerable uncertainty about future LNG prices, the Commission modelled baseline scenarios with low, central and high LNG prices. All three baselines included the three existing LNG export projects at Gladstone. Noting that the model was not designed to forecast prices, but rather provide an illustration of market relationships, the model’s results suggest that although eastern Australian gas market prices will move with LNG prices, this link would be weaker if LNG prices are low. This is because LNG quantities are locked in through export contracts while they remain in force, and there is limited scope to shift supply to the eastern Australian gas market in response to a decline in the LNG price. In such circumstances, prices in the eastern market would temporarily exceed the LNG netback price in the

absence of other factors that could increase the total supply of gas from the east coast of Australia (such as productivity improvements or cost decreases in gas production).

Box 3.3 Factors that could influence gas prices in the eastern Australian gas market

Prices in the eastern Australian gas market could be influenced by many potential factors and may diverge from LNG netback prices at any given time.

- Uncertainty about future LNG prices coupled with the lumpy nature of investment in LNG facilities and lags in bringing those facilities online could cause prices in the eastern Australian gas market to temporarily under or overshoot LNG netback prices. A complicating factor is that most current LNG contracts are explicitly linked to world oil prices, which have fallen substantially recently both in US dollar terms and Australian dollar terms.⁴
- Long-term contracts that have historically dominated the eastern Australian gas market can mean that prices on the east coast would be slow to respond to unexpected changes in the Asia–Pacific market. The eastern Australian gas market is not as well developed and does not have the liquidity or depth of gas markets in some other countries.
- Export contract conditions, including penalty clauses for failure to meet the supply commitments and limits on the ability to substitute gas from sources elsewhere (including overseas), can mean that any supply constraints would be borne by gas users in the eastern Australian gas market. Uncertainties about well deliverability and regulatory impediments to increasing supply are particularly important in this context.

What are the community-wide effects of international linkage?

A number of studies have concluded that the development of export capacity has had, and will have, considerable economic benefits for Gladstone and the surrounding region. The Australian Petroleum Production and Exploration Association found that development of LNG capacity has led to \$63 billion in investment and the creation of almost 30 000 jobs during the construction phase (APPEA 2013b). Energy Skills Queensland (cited in BREE 2014b) estimated that these projects will employ up to 17 000 people, directly or as contractors, when full production is reached after 2020.

However, there are concerns about the effects of rising gas prices on Australian gas users. Integration with the Asia–Pacific market is creating significant disruption for eastern market participants. Some large gas users have reported difficulties securing gas contracts (AIG 2013), and indicated they may be forced to reduce output or exit Australian manufacturing altogether. In a report prepared for several stakeholders from the manufacturing sector, Deloitte Access Economics noted that the integration of the eastern Australian gas market with the Asia-Pacific market posed significant challenges to the

⁴ During the course of this project oil prices have fallen to levels not seen since 2009. Crude oil prices (as measured by the average spot price of Brent, Dubai and West Texas Intermediate) have fallen from about \$US105 (\$A115) per barrel in July 2014 to \$US55 (\$A70) in February 2015 (World Bank 2015a).

operations of some manufacturing companies, such as Australian Paper's Mill at Maryvale, Victoria. The report stated that '... recontracting at higher oil-linked gas prices could undermine the viability of the Maryvale Mill's operations ... Without access to an affordable, reliable gas supply, it is highly likely that the Mill's operations would be significantly curtailed, leaving little or no scope to undertake future or even continued investment.' (Deloitte Access Economics 2014, p. 49).

These concerns have led some stakeholders to propose implementing a domestic gas reservation policy in the eastern market (Manufacturing Australia 2014b) or to apply a 'national interest test' to LNG exports (AIG 2013) (discussed in more detail in chapter 7). A domestic gas reservation policy currently exists in Western Australia. In Queensland there is a reservation policy in which domestic supply conditions can be included in exploration licences where domestic supply constraints are identified. A number of the concerns expressed by gas users in the eastern Australian gas market have also been raised by users in the western market. For example, the Western Australian energy user group DomGas Alliance, submitted to the Western Australian Government's Electricity Market Review:

... industry is already experiencing difficulty in securing long-term supplies of natural gas, regardless of price ... Recent experience has outlined the clear preference (and in some cases the determination) of producers to direct all of the resources of a project toward export at the expense of domestic supply. (2014a, p. 4)

The precise effects of higher gas prices on particular domestic users in the eastern Australian gas market will vary depending on many factors, including: the gas intensity of the user's activities; the cost of switching to alternative fuel sources or products; and the capacity for commercial and industrial users to pass on some or all of the price increases to consumers.

However, it is likely that there will be material costs for some gas users. As noted above, there are a number of large industrial users in the manufacturing industry who use gas as a feedstock, or use gas in industrial applications such as aluminium smelting and brick manufacturing, making substitution to alternative energy sources or products difficult. The manufacturing sector is also largely trade exposed, and hence many companies have limited ability to raise prices in response to an increase in their costs (PACIA 2014).

However, while the current structural pressures within the eastern Australian gas market are significant, they are not unique to this market, nor are they an indicator of net loss to the broader Australian community. Markets are dynamic, and producers and consumers are continually adapting to the entry and exit of participants, changes in technology, market institutions, and changes in prices, in addition to a multitude of other factors. The process of structural adjustment allows resources to move to their most highly valued uses. It also encourages more efficient production processes, and the generation of greater value for consumers.

In the eastern Australian gas market, resource discoveries and changes in production technology have enabled the market to link to the Asia–Pacific, where gas is valued at a higher price. This is the fundamental driving force behind the increase in gas prices for gas users on the east coast.

Petroleum and mineral resources in Australia are owned by the Crown and gas producers pay royalties and taxes on the value of the gas they produce. The integration of the eastern Australian gas market with the Asia-Pacific, therefore, represents an opportunity for Australia to earn a higher return from its non-renewable resources, than if the market had remained closed to international trade. The benefits from exporting can reach the wider community via resource royalty and taxation payments, which is subsequently invested in a range of areas including physical or human capital for the benefit of current and future generations.

In addition, higher gas prices provide a signal that more resources should be allocated to production activities associated with gas, as additional resources are more highly valued in those applications. The result is greater investment in the gas industry, and an overall reallocation of the economy’s resources into areas of their highest value use, consistent with improving allocative and dynamic efficiency (chapter 2).

Structural adjustment regrettably imposes costs on some individuals, regions and industries, while others will benefit. How those costs and benefits will be distributed across the Australian community is influenced by a number of factors. However, this does not change the core premise that it is no longer *efficient*, or in the best interests of the Australian community, to sell gas at prices that prevailed before the linkage to the Asia–Pacific market. Nevertheless, the effects of linking the eastern Australian gas market with the Asia-Pacific market should not be ignored by governments. The process of structural change increases the imperative for reform and magnifies the consequences of any policy errors. The significant change currently underway in the eastern Australian gas market underscores the importance of policies across the gas supply chain that facilitate (rather than impede) adjustment, and allow resources to move to their most highly valued uses.

4 Designing and allocating gas exploration and production rights

Key points

- The objective of tenement regimes should be to maximise resource rent by optimising the level and timing of resource exploration and production.
 - Maximising the net present value of resource rent over time benefits the wider community through royalty and taxation revenue.
- Some large industrial gas users have suggested that gas companies are hoarding reserves, rather than developing them for production.
 - What may appear to be hoarding of reserves could in fact be commercial behaviour that is consistent with outcomes from effectively competitive markets, given current and expected gas prices, production costs and risk preferences.
- Policies designed to accelerate production, such as use it or lose it mechanisms, risk pushing extraction beyond efficient levels and are unlikely to lead to material benefits for gas users.
 - A use it or lose it mechanism may not result in additional gas being supplied, and even if it did, there is no assurance that additional gas would be channelled to domestic users rather than export markets.
 - Given the integration of the eastern Australian gas market with the Asia–Pacific market, a use it or lose it policy is also unlikely to affect the price paid by gas users.
- Most gas tenements in Australia are allocated via administrative determinations based on the proposed work program submitted by bidding companies.
 - Transparency in the criteria used for allocating tenements can help ensure that actions undertaken for work programs are relevant to actual exploration activity.
- In 2014, cash bidding was reintroduced to allocate selected offshore petroleum tenements in Commonwealth waters, and has also been used to allocate some tenements in Queensland since October 2012.
 - Cash bidding has efficiency advantages over work program bidding, and is a method of appropriating resource rent on an upfront basis. However, it has challenges of its own, such as the need to design an auction system that promotes efficiency.
 - There is merit in observing the operation of the cash bidding systems for offshore petroleum in Commonwealth waters and in Queensland to assess their efficiency, and draw lessons on system design challenges and the scope for their broader application.

As discussed in chapter 2, an increase in economic efficiency enhances overall community wellbeing. The design of rights for exploring and producing gas resources, as well as the method by which those rights are allocated, significantly affects efficiency in gas markets

by influencing the magnitude of exploration or production activity, its timing, and which parties undertake it. There may also be implications for the distribution of the costs and benefits of exploration and production among gas companies, gas users, and the wider community.

This chapter examines some of the policy issues that are a feature of the current debate about promoting economic efficiency in the design and allocation of gas exploration and production rights.

4.1 What is a tenement?

In Australia, mineral and energy resources are owned by the Crown, regardless of who owns surface rights to the land. Oil and gas resources located offshore outside the three nautical mile territorial limit, up to the boundary of Australia's Exclusive Economic Zone are the responsibility of the Australian Government. State and territory governments possess responsibility for the mineral and energy resources located in their respective jurisdictions (Department of Industry nd).

In relation to mineral and energy resources, a tenement refers to a claim, lease or licence that gives its holder the right to explore for resources or to undertake production. The three main approaches used by Australian jurisdictions for conferring rights to resources are exploration licences, retention leases and production licences.

Generally, the process for allocating rights begins with an exploration licence, which permits the holder to explore for resources on a specified area of land. In the case of gas, but also other resources, areas of land available for exploration are usually nominated or advertised by the minister in the relevant jurisdiction, and the gas company that obtains the right to explore usually does so on the basis of its work program bid, although cash bidding and first come first served are also used to allocate tenements (section 4.3).

Exploration licences are time-limited (section 4.2). At expiration, a company may choose to renew its licence, surrender its licence (and hence the right to further explore the area), or apply for a production licence if gas has been discovered. An alternative option if the company discovers gas is to apply for what is generally known as a retention lease. Retention leases enable explorers to maintain an interest in areas of land containing mineral or energy resources where extraction is not yet commercially viable.¹ They aim to protect the interests of companies undertaking high risk, high cost exploration, and enable them to utilise their knowledge of the extent and type of resources, as well as the commercial potential of those resources. The objectives of retention leases are typically balanced by the desire of governments to see resources developed.

¹ Retention leases may be known under different names in different jurisdictions. For example, in New South Wales, retention leases are referred to as assessment leases, while in Queensland they are known as potential commercial areas.

New South Wales has described the rationale for retention leases as being to:

... allow the developer to maintain a title over a potential project area, without necessarily having to commit to further exploration ... However, these leases are not intended to allow the holders to tie up resources indefinitely and there is an expectation that there will be direct expenditure on the area. (NSW DPI 2008, p. 1)

Like exploration licences, retention leases are also time-limited — for example, in Queensland, potential commercial areas have a maximum term of up to 15 years (Queensland Government 2014a), and 15 years is also the maximum term for onshore petroleum retention leases in Victoria (State Government of Victoria 2015). Rules for the renewal of retention leases differ across jurisdictions. For example, retention leases for Commonwealth offshore petroleum (which have a duration of five years) may be renewed (DRET 2012), whereas retention leases for onshore petroleum in Victoria and Queensland cannot be renewed (DEDJTR 2014; Queensland Government 2014a).

After exploration has uncovered gas resources that can be commercially developed, a company may apply for a production licence, which enables it to undertake gas production in the specified area of land. Gas companies pay royalties on production, or profit-based taxes in return for the right to extract non-renewable resources.

In general, exploration licences, retention leases and production licences may be traded, with legislation in Australian jurisdictions typically requiring that approval by the relevant minister or government department be granted before a transfer of rights can occur.

Requiring approval for transfers can be an important oversight mechanism, ensuring that transfers do not become a means of avoiding licence approval and other regulatory processes by gas companies. The ability to transfer resource rights is an economically desirable aspect of the system for allocating such rights (chapter 2). It enables rights to be transferred to those who value them most highly, facilitating allocative (and dynamic) efficiency. In the case of retention leases, the ability to transfer rights can also help ensure that companies most adept at developing resources obtain the rights to do so (promoting productive efficiency). It is therefore important to ensure that there are no undue impediments to the trading of exploration and production licences in secondary markets.

In this report, the term ‘tenement’ is used to broadly describe the system of exploration licences, retention leases, and production licences, all of which give their holders rights to undertake activity in gas fields.

The tenement regime and resource rent

Ultimately, the economic objective of gas tenement regimes should be to enhance efficiency. A key aspect of economic efficiency in the context of non-renewable resources is that of ‘economic rent’, defined as the value of production when all necessary costs have been deducted (Hogan 2003). In a competitive market, the economic rent from the exploration and production of non-renewable resources is the difference between revenue

and costs, where the latter incorporates a ‘normal’ rate of return on capital. The normal rate of return on capital is the minimum return required to induce capital to remain in the industry, and includes a risk premium (Hinchy, Fisher and Wallace 1989; Hogan 2003).

Usually, the presence of economic rent would typically attract new entrants to the industry, dissipating the rent. In the case of non-renewable resources however, rents may persist for two reasons:

1. quality differential rent: the costs of extraction and marketing differ across fields — for a given gas price, companies with access to superior, low-cost deposits will be able to earn greater revenue over costs than companies with access to marginal deposits (all else equal)
2. scarcity rent: since a company can produce gas now, or at a future date, in order to extract now, the return the company earns must at least equal the net present value of extraction at a future date — that is, there is an opportunity cost associated with foregoing future production when gas is produced now (Hinchy, Fisher and Wallace 1989; Hogan 2003).

Dynamic efficiency can be achieved if the net present value of resource rent is maximised over time. By doing so, the community will be in a position to enjoy the highest net benefits from the depletion of gas resources. The community would realise benefits via taxation mechanisms including royalties and the Petroleum Resource Rent Tax (aspects of resource taxation are considered further in section 4.4), and gas companies would benefit through maximised profits over time.

4.2 Tenement design and the timing of exploration and production

The objective of gas tenement regimes in all jurisdictions should be to maximise resource rent, which entails optimising the timing of exploration and production. Well-designed tenement regimes enable gas companies to make production and investment decisions on the basis of market signals through time. There are several ways in which the design of tenements can influence the timing of exploration and production — as well as the relationship between these two activities — such as by setting limits on the duration of the tenement, and by imposing ‘use it or lose it’ conditions on the tenement.

Tenement duration, renewal and relinquishment

In most jurisdictions, gas exploration and production is regulated under petroleum legislation, for both onshore and offshore deposits (Ross and Darby 2013). The majority of jurisdictions impose maximum terms for gas exploration licences. Typically these are set at between four to six years, although the relevant minister determines maximum terms in Queensland and Tasmania for onshore petroleum (table 4.1).

Table 4.1 Maximum duration of exploration licences^a

Years

	<i>Onshore mineral</i>	<i>Onshore petroleum</i>	<i>Offshore mineral</i>	<i>Offshore petroleum</i>
NSW	5	6	4	6
Vic	5	5	5	6
Qld	5	Ministerial determination	4	6
WA	5	6	4	6
SA	5	5	4	6
Tas	5	Ministerial determination	5	6
NT	6	5	6	6
Cth	na	na	4	6

^a In most Australian jurisdictions, gas resources are regulated under petroleum legislation. However, in Victoria, the exploration and production of coal seam gas resources are regulated under the *Mineral Resources (Sustainable Development) Act 1990* (Vic).

Sources: PC (2013b); Ross and Darby (2013); State Government of Victoria (2015).

Tenements are also subject to rules relating to renewal, such as the number of times a licence can be renewed, and relinquishment requirements. The latter specify the proportion of the original area of a tenement that must be surrendered when an application for renewal is made. Notionally, relinquishment requirements are in place to promote the turnover of tenements and facilitate exploration by other interested parties.

For example, the Australian Government's exploration permit renewal and relinquishment rules for offshore petroleum typically require titleholders to relinquish half of the blocks held under an existing exploration permit at each application for renewal. A titleholder does however have the discretion to nominate the blocks from its exploration licence that it wants to have renewed. Similarly, in Queensland, the holder of an authority to prospect (exploration licence) may choose the blocks it wishes to have renewed, provided they do not exceed the maximum number of blocks that can be held upon renewal.

The stated reason for the relinquishment requirement is to encourage 'substantial' exploration and facilitate extended tender over those areas regarded by a titleholder as being more prospective (Department of Industry 2014f).

Should governments seek to influence the timing and magnitude of exploration and production?

Retention leases, timing and the transition to production

Some large industrial gas users have suggested that the current arrangements regarding retention leases are flawed and have enabled the 'hoarding' of gas. For instance, DomGas

Alliance, in its submission to the Eastern Australian Domestic Gas Market Study stated that, in relation to retention leases:

... additional fields are being labelled as unviable to develop when they are, in essence, being stockpiled as future supply for the out-years of long-term LNG export contracts (DomGas Alliance 2014b, p. 10).

There is insufficient evidence available to the Commission to determine whether gas producers are restricting the quantity of gas available by hoarding reserves.

Gas companies have an incentive to maximise the value of resource rent over time. Where markets function well, this is consistent with promoting efficiency, and overall community wellbeing. Depending on market conditions, this means that gas companies will not necessarily undertake production at the earliest possible date and fully exploit their resource until it has been exhausted. Again, it is critical that the companies which value tenements most highly are those that hold them — a condition encouraged by the ability to transfer rights (chapter 2).

A key factor behind the decision on whether and when to develop a reserve and commence production is the cost of production, which varies from field to field, and expectations of future gas prices, among other factors. However, expectations of future prices can be unreliable, as the recent unexpected fall in oil prices demonstrates (chapter 3). For a gas producer to deliberately hold off on production of a potentially profitable reserve on the expectation of a higher future price involves a risk, as the future price could be lower. The cost of production could also be higher, even if partially offset by productivity improvements. The profits which are foregone today could be invested elsewhere — this is the opportunity cost of a deliberate delay in gas production. For a producer to find a strategy of holding off production profitable, net prices (the market price of the resource less its extraction cost) would need to increase faster than the rate of interest. Only under such a circumstance would delaying production (or reducing the rate of gas extraction) maximise the value of the reserve over time. Henry et al. remarked:

Arguments for exploration and production faster than this rate [the interest rate] can fail to recognise that resources kept in the ground will generate a better return for the owner if higher rents can be obtained in the future (due to future higher prices or lower exploration and production costs). (2009, pp. 218–9)

This highlights the importance of considering all aspects of resource rent, including production costs. If production costs were expected to fall over time, companies would have a similar incentive to delay production as they would for a rise in expected future prices, all else equal.

Ultimately, when gas producers decide to hold off on some production purely because they can earn higher rents based on expectations of future prices and production costs, such activity is not a cause for concern on efficiency grounds. However, if a gas company had market power, and reduced production because doing so would allow it to increase prices, such an outcome would be inefficient (chapter 2).

A further reason for what might initially appear to be hoarding concerns the export contracts entered into by many gas companies in eastern Australia. Current LNG export commitments are effectively locked-in in the short term, and penalties and other costs exist for exporters that are unable to meet their contractual commitments. Gas producers may err on the side of caution and ensure they have enough gas available to meet export commitments, rather than risk running short.

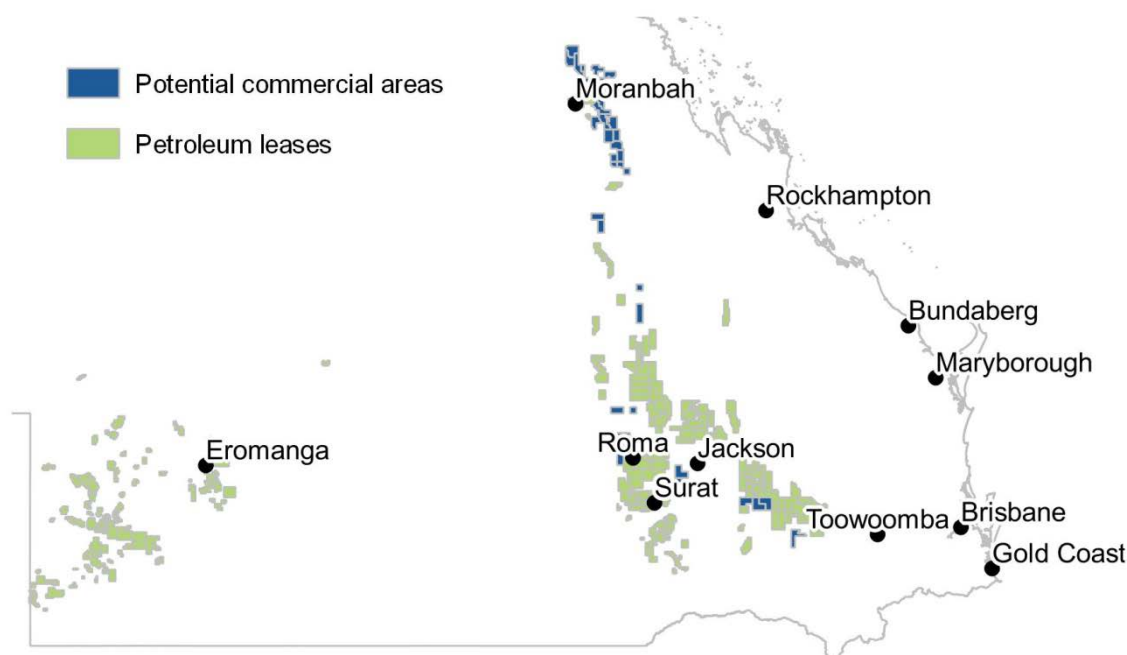
Some information may be gleaned by looking at the number of production licences compared to retention leases, if the latter are suspected or alleged to facilitate hoarding. In Queensland, where a significant share of gas production occurs (chapter 3), onshore petroleum production licences significantly outnumber potential commercial areas (that state's equivalent to a retention lease).² There are currently almost 270 active licences and less than 40 'potential commercial areas'. In effect, there are more licences allowing oil and gas companies to undertake activities that are directly connected with petroleum production than there are leases that allow companies to retain areas containing deposits without undertaking production or related activities. The area of land occupied by petroleum leases is also significantly larger than that occupied by potential commercial areas (figure 4.1).

The Economics and Industry Standing Committee of Western Australia examined the regulatory arrangements relating to licences in that state and the evidence on reserves in 2011. It accepted that retention leases could be important for prospective LNG producers to enable them to build sufficient reserves to achieve commerciality. The Committee was not able to verify that LNG producers were using retention leases to warehouse or hoard reserves. It did, however, conclude that the processes for the application and renewal of retention leases were lacking in rigour and enabled (but did not necessarily result in) the warehousing of gas reserves by incumbent producers (EISC 2011).

In sum, pressure to bring forward production by altering the parameters of retention leases might not have the intended effect, depending on the strength of the influence of other factors. In addition, attempts to bring forward production at a time that is not of the choosing of gas companies risks dissipating resource rent, and therefore, limiting the ability to maximise the benefits from the extraction of non-renewable resources. It may also have the effect of reducing incentives to invest, distorting future resource allocation. These outcomes depend however, on exploration licences, retention leases, and production licences being held by those who value them most highly, underscoring the importance of the transferability of resource rights (chapter 2).

² In Queensland, production licences give their holders the right to explore for petroleum, test for petroleum production, and produce petroleum. Hence, production licences are associated with petroleum production, or activities leading towards production. Potential commercial areas give holders the right to retain areas containing resources which need more time to be commercially developed.

Figure 4.1 Current onshore petroleum licences in Queensland^{a, b}



^a Petroleum leases give holders the right to explore for, test for the production of, and produce, petroleum. Potential commercial areas allow holders to retain areas to provide additional time to commercialise petroleum resources. ^b Petroleum leases and potential commercial areas shown on the map are those which have been approved; this does not include those for which an application has been made, but which are awaiting approval.

Source: Map constructed using Queensland Government (2015a).

Information spillovers

One rationale for time limits on exploration licences along with relinquishment requirements is based on information ‘spillovers’ (chapter 2). When the tenement holder cannot capture all of the benefits from exploration — because information obtained from exploring a tenement might provide some insights to other explorers about nearby areas — exploration and production may be pushed below optimal levels. Turning over tenements may therefore result in improved information dissemination.

However, the imposition of conditions on tenements is unlikely to be the most efficient means by which to address any information spillovers that might occur in gas exploration. Information can also be exchanged between explorers and producers via market transactions. For example, a gas company undertaking exploration could pay owners of nearby tenements for detailed geological information, if it thought that information might assist its own exploration efforts.

In its submission to the Eastern Australian Domestic Gas Market study, the Australian Petroleum Production and Exploration Association (APPEA) noted that current

precompetitive geoscience capacity informs the ability of governments to make decisions on the location of areas that are likely to be viable for private exploration. APPEA recommended that governments continue to fund precompetitive geoscientific studies, as well as investigate ways in which the existing repository of geoscientific information could be better used to attract investment (APPEA 2014d). Similarly, the Australian Pipeline Industry Association argued (in its submission to the Energy White Paper) that while a range of geoscientific information is available through government organisations, information arrangements could be improved. The Association suggested that this be done by increasing the quantity of data released, and reducing the timeframes applicable for the release of privately captured data (APIA 2014b).

Restrictive tenement conditions can be costly and may not work

Will tenement management create substantial benefits for domestic users?

Proponents of policies to reform and manage tenements argue that reforms to tenement systems will provide benefits for domestic gas users. For example, the Australian Industry Group's submission to the Competition Policy Review suggested that use it or lose it mechanisms be considered for gas tenements due to their ability to 'provide a valuable tool to ensure that much needed supply is not deliberately withheld' (AIG 2014b, p. 42). The argument suggests that greater quantities of gas will be delivered to domestic markets, lowering prices for users.

However, as mentioned above, gas companies have an incentive to maximise their profits, which will lead them to deliver their gas to whichever customers are consistent with this objective (given the costs of distribution to domestic pipelines compared to transfer to export terminals and the capacity of extant processing facilities). Accordingly, a use it or lose it mechanism may not actually result in any additional gas being brought to market if the costs of producing and transporting it are beyond the willingness of potential customers to pay for it. The Commission concluded in 2009 (PC 2009) that the introduction of use it or lose it mechanisms, in an attempt to bring forward exploration and production, might actually be counterproductive:

An automatic 'use it or lose it' policy is a blunt instrument subject to significant risks of regulatory error and may result in the perverse long-term outcome of both reduced exploration and reduced commercialisation of resources. (p. 95)

In the event that use it or lose it does bring additional gas to the market, there is no assurance that it will be channelled to domestic users, if gas companies can receive higher returns by exporting it instead — it is therefore unlikely to reduce domestic prices.

Furthermore, limits placed on the ability of companies to make commercial decisions relating to their tenements could blunt the incentive to invest in exploration activity (PC 2009). In the long run, a decline in investment for exploration could reduce the supply of gas to a level lower than what persisted before the application of use it or lose it

mechanisms. In this sense, a condition such as a use it or lose it mechanism could actually harm the users the mechanism is aimed to assist.

Excessively short tenure for tenements could also result in a last-minute flurry of exploration activity, prior to the expiration of existing exploration permits. This activity may inflate production costs at the end of a tenement's term, and also lead to inefficient investment and production decisions over time. Pressure to undertake inefficient exploratory activity can be compounded by relinquishment requirements.

As the Industry Commission remarked, relinquishment:

... places explorers in a double bind, further encouraging what — if there were time for considered reflection — would likely to be judged to be ill-conceived and precipitate exploration activity. (IC 1991, vol. 3, p. 38)

In the context of Commonwealth offshore petroleum, ACIL Tasman (2012) concluded:

Short tenure would be most likely to bring forward exploration in areas not yet considered prime targets. These may be the areas in which information provided as 'spillovers' would be most valuable ... However, they may also be the areas in which exploration is most likely to be commercially premature ... highly conditional tenure could discourage very early take up of exploration permits, with the result that there would be no informational 'spillovers' in those cases. (p. 101)

The result might be that the conditions placed on tenements actually reduce, rather than increase, the quantities of gas discovered and produced.

Potential for lost economies of scale

Tenement conditions can also have implications for the efficiency of the scale of exploration and production activities. A risk associated with relinquishment requirements is that, by progressively reducing the size of leases, a point might be reached where the average size of leases becomes inefficiently small. Exploration costs would rise due to a loss of economies of scale (IC 1991).

A further risk of continually reducing the average size of exploration and production plots is that it may encourage too many entities to undertake exploration activity, where it may otherwise be more efficient for a smaller number of entities to search for gas resources. In effect, too much of society's scarce resources would be allocated to exploring for gas, instead of undertaking other productive activities.

4.3 Allocation of exploration licences

In Australia, there are three main mechanisms used to allocate exploration licences: work program bidding, first come first served, and cash bidding (PC 2013b). The choice of tenement allocation mechanism can affect the overall efficiency of gas exploration and

production activity, and also has potential equity effects. Choosing the right mechanism can be difficult in view of these trade-offs, and the answer may also be influenced by context. Nevertheless, a robust and transparent economic framework can assist in bringing those issues into sharper focus. It is not clear that existing arrangements have been underpinned by such analysis.

Work program bidding

Work program bidding requires interested parties to specify the exploration activity they intend to undertake in the event of being granted a tenement. The relevant authority then decides which bid to accept, based on how well the work programs of the bidding parties are perceived to meet regulatory and other policy objectives (PC 2013b). To ensure impartiality and system integrity, probity standards can be set, thereby underpinning the transparency and objectivity of the system. (The same is true for cash bidding, discussed below.)

Bids may outline the nature and extent of activities such as drilling of exploration wells, and geochemical analysis that bidders will undertake, should they secure the tenement. For example, in Victoria the work program bidding system to allocate petroleum exploration licences involves:

... the agreed technical work that a company undertakes over the term of its exploration permit. Each work element is allocated to a particular year over the term. That work can be G&G [geological and geophysical] studies, surveying, seismic wells and typically builds understanding towards a well. (DSDBI 2014, p. 1)

In Australia, work program bidding is a commonly used mechanism at the Commonwealth and state level. In 2014, 26 of the 30 areas released by the Australian Government for offshore petroleum exploration were allocated by work program bidding. The bid assessment criteria included (but were not restricted to):

- the number and timing of exploration wells to be drilled
- the amount, type and timing of seismic surveying to be carried out
- other new surveying, data acquisition and reprocessing to be carried out
- the type, scope and objectives of the geotechnical studies proposed within the area. (Department of Industry 2014a)

Potential for excessive exploration

A number of analyses of tenement allocation mechanisms concluded that work program bidding is likely to result in tenement holders undertaking too much exploration, and/or that exploration activity will occur too soon (ACIL Tasman 2012; Henry et al. 2009; IC 1991; Willett 2002). ACIL Tasman remarked:

Work program bidding was designed to allocate tenements and to elicit offers of greater and earlier exploration expenditure. (2012, p. 22)

For example, the provisions of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) provide that where applicants for a petroleum exploration permit are ‘equally deserving’, the applicants may be invited to provide details of their proposals for additional work and expenditure in relation to the block or blocks concerned (ss. 106(6)).

The benefits of expenditure on exploration are not constantly increasing. Greater expenditure on exploration than is strictly necessary has the effect of increasing the costs incurred by gas companies, reducing efficiency, and dissipating resource rent. In extreme cases, so that they can secure a tenement, a gas company may commit itself to a work program that erodes all of the expected resource rents. In the event that a company over-commits to a work program, it may later seek exemptions from government in meeting its obligations. (This might also occur if a tenement contains fewer deposits, or deposits more expensive to extract, than initially anticipated.) This would have efficiency and, importantly, equity implications, as a more suitable developer (with more realistic intentions) may have lost out in the process. A lack of enforcement of tenement conditions would also have the effect of calling the system’s credibility into question.

The Australian Pipeline Industry Association in its submission to the Energy White Paper process also noted the limitations of work program bidding. Observing that the majority of gas exploration tenements in Australia were offered via work program bidding on the assumption that early and more exploration is desirable, the Association concluded that:

... tenement allocation systems designed to increase the pace of exploration can lead to a misallocation of exploration resources, with proponents committing to more than necessary exploration work to secure a tenement. This misallocation leads to other areas not receiving enough exploration resources, diminishing the size of Australia’s total gas reserves, gas supply, and tax revenue. (APIA 2014b, p. 6)

Arbitrary non-transparent criteria and outcomes

Another shortcoming of the work program bidding system is that it potentially provides scope for arbitrary and inefficient outcomes via the selection of the work program criteria. The Commission observed in its report on *Mineral and Energy Resource Exploration*:

Explorers will tend to adopt techniques, plan drilling activity or assign exploration expenditures to those activities that match the criteria used by governments to allocate a tenement, even though these choices may not be the most cost effective for the explorer. (PC 2013b, p. 11)

The Commission consequently recommended that government authorities responsible for exploration licensing publish information on licensing and objectives, and the criteria by which applications for licences will be assessed. It also recommended that the outcome of exploration licence allocation assessments be published, including the reasons why the winning bid was successful (PC 2013b). Where allocation methods like work program bidding are used, increased transparency in decision-making could limit any tendency for the work program criteria selected to be of limited relevance to actual exploration activity.

High administrative costs

Work program bidding can impose relatively high administrative costs on governments and the industry. For governments, the need to take multiple factors into consideration — such as the timing of activity, type of drilling undertaken and any geological data that may be obtained — increases the complexity of the assessment task (PC 2013b).

Past analysis has also uncovered:

- recurring uncertainties regarding the reliability of the system (IC 1991)
- bureaucratic/ministerial involvement and discretion with respect to some issues (also discussed by the Industry Commission (IC 1991)
- a requirement for substantial monitoring of effort relating to the work programme, relinquishment, and other requirements (Willett 2002).

Implications for equity

Sub-optimal exploration activity has a direct effect on the benefits received by the community from the gas resource. There are two main channels through which this will manifest itself — a reduced stream of royalty and taxation payments, and a greater level of deductions for exploration costs (ACIL Tasman 2012). This directly affects the resource rent that can be appropriated and distributed to the community. Furthermore, if tenements are allocated on the basis of a commitment to accelerate exploration and production, there are implications for intergenerational equity. Extracting the gas before it is optimal to do so denies future generations some (if not all) of the value of the resource (chapter 2). (The same concerns apply to first come first served allocation, discussed below.)

First come first served

Under the first come first served system (sometimes also referred to as ‘over the counter’), exploration rights are allocated to the first applicant to apply for them. Interested parties may apply for an exploration licence where exploration is permitted, but where there are no active exploration licences.

Alternatively, areas may be released for exploration, either for the first time, or following the surrender of existing tenements. In Australia, exploration licences are generally allocated on this basis where there is likely to be only one party interested in exploring an area covered by a tenement (PC 2013b). Licences are typically subject to performance of a minimum work program, with timing determined by, or negotiated with, the relevant government (box 4.1).

Box 4.1 Onshore petroleum and first come first served in South Australia

In South Australia, the *Petroleum and Geothermal Energy Act 2000* (SA) and associated Petroleum and Geothermal Energy Regulations 2013 govern the allocation of tenements for onshore petroleum resources. The tenement allocation regime under the legislation incorporates an over the counter mechanism, giving explorers the ability to apply for exploration licences for areas they desire. The system allows applications for a petroleum exploration licence to be lodged at any time over any area of the state, provided the area is not classified as a Competitive Tender Region (an area considered to be highly prospective for petroleum exploration or exploration of other resources).

Upon the submission of an over the counter Petroleum Exploration Licence application, either the grant of a licence, or a process leading to the grant of a licence, will be offered to the applicant. Once a licence has been granted, or a process leading to the grant of a licence has commenced, the application is given primacy; any other applications received by prospective explorers are held in abeyance, pending the outcome of the application with primacy.

The Act specifies that a mandatory condition of an exploration licence is that the licensee be required to carry out exploration in accordance with a work program approved by the Minister. A proposed work program must be submitted with an application for an exploration licence, or an application for licence renewal. The Minister may approve a proposed work program, or alternatively make additions or vary the work program.

Sources: DSD (2013a, 2013b).

Where applications for exploration rights are received simultaneously, rights can be allocated via a ballot, or by assessing the work programs of the bidding parties. In the latter case, first come first serve in effect resorts to a form of work program bidding. Should commercially valuable resources be discovered, the holder of the exploration licence will typically be given priority when applying for production rights. However, production licences may also be subject to additional conditions that differ from those of the exploration licence. Consequently, exploration and production licences granted under the first come first served method may require the satisfaction of a number of conditions by interested parties.

Drawbacks of first come first served

The fact that applicants face virtually no cost to secure a tenement can create a race to lock up land, and combined with restrictive tenement conditions, may lead to over-exploration

and excessive exploration expenditure. The Industry Commission (1991) argued of first come first served allocation mechanisms that:

The imperative to acquire rights over land which is considered at all prospective before somebody else does, combined with the fact that such rights can only be held for a relatively short time unless a discovery is made, provides incentives for exploration companies to acquire tenements and to conduct exploration as soon as the expected net returns from exploring are judged to be even marginally positive. (vol. 3, p. 41)

In their pure form, first come first served arrangements involve low administrative costs. However, these advantages dissipate when there are multiple candidates for the same tenement, necessitating bureaucratic and ministerial involvement and discretion (Willett 2002). As with work program bidding, first come first served with highly conditional tenure also requires monitoring activity by both governments and explorers, leading to further administrative costs (ACIL Tasman 2012; Willett 2002).

Cash bidding

Under a cash bidding system, interested parties are invited to submit bids for exploration rights, and the party that offers the highest cash bid is granted the rights to the resource. A pure cash bidding model allows the party with the winning bid to execute what it regards as an optimal extraction program — thus, it can decide when market conditions are most favourable for production. In practice, cash bidding models often include conditions for receiving a licence, such as minimum exploration requirements (PC 2013b). Bidding parties will also typically be required to demonstrate the technical competence and financial resources required for exploration activity as part of their bid. Other conditions may also need to be met — for example, under Queensland’s cash bidding system a preferred tenderer is also required to satisfy a number of environmental and tenure approval requirements before an exploration tenement is granted (DNRM 2014).

After operating temporarily between 1985 and 1992, cash bidding was reintroduced by the Australian Government in 2014 to allocate offshore petroleum exploration permits for mature areas, or areas known to contain petroleum accumulations (Department of Industry 2014c). Of the 30 areas released by the Australian Government for offshore petroleum exploration in 2014, four were made available for cash bidding (Department of Industry 2014e).

In October 2012, the Queensland Government announced that it would introduce cash bidding for selected coal, petroleum and gas tenements. Hence, Queensland still releases areas for exploration without a cash bid component. As of July 2013, a total of 2829 sub-blocks had been released through the competitive tender process in Queensland without a cash bidding component. By comparison, the first two rounds of cash bidding held in Queensland released 147 sub-blocks for potentially highly prospective coal seam gas deposits (Queensland Government 2013).

Even when the Queensland Government uses cash bidding, it continues to use a work program as an evaluation criterion. The Queensland Government (2013) argues that this method ‘provides a balanced assessment of tenders since the highest cash bid does not necessarily guarantee the most suitable approach to exploration and development’ (p. 8). Introducing elements of work program bidding into a cash bidding framework does, however, risk creating complexity and uncertainty for bidding companies, dissipating the relative benefits of cash bidding over work program bidding. It also risks introducing the potential inefficiencies associated with aspects of work program bidding (discussed above) into the allocation system.

Cash bidding as a tenement allocation mechanism has also been used in overseas jurisdictions. For instance, in the United States, offshore and onshore oil and gas leases are allocated via competitive, ‘bonus-bid’ auctions (box 4.2).

Box 4.2 Cash bidding for oil and gas tenements in the United States

In the United States (US), federal onshore and offshore leases for oil and gas resources are awarded on the basis of competitive, ‘bonus-bid’ auctions. Under this system, winning bidders pay not only the value of their bid, but also pay a per acre rent prior to the commencement of production. After production has begun, royalties are paid. Onshore royalty rates are typically 12.5 per cent, whilst offshore rates range between 12.5 per cent and 18.75 per cent.

The auction processes differ between onshore and offshore resources. Onshore resources are nominated for leasing by interested parties, and those parcels subsequently identified by the US Bureau of Land Management as available for leasing are then sold at auction using an oral bidding process. In the event that a parcel is not sold at auction, after two years the Bureau may offer it on an over the counter basis. For offshore resources, the land available for leasing is identified via public comment, and a five-year leasing program is published. A sealed bid auction process follows, in which the highest qualified bidder is awarded the lease.

Auctions have been used to allocate exploration and drilling rights for oil and gas on federal lands on the US Outer Continental Shelf since 1954, where a large proportion of bidding and production has been in the Gulf of Mexico.

In 1983, area wide leasing was introduced in the US Outer Continental Shelf, which opened large planning areas for lease auctions and removed the requirement on companies to nominate a tract of land for a tenement to be offered for sale. The move resulted in a decline of successful auctions from 49 per cent between 1954 and 1982, to 7 per cent between 1983 and 2006. Although receiving support from industry, area wide leasing has received criticism from a number of environmental groups and some coastal states.

In the case of onshore US resources, from 2009 to 2013, approximately 22.3 million acres of land were offered at oil and gas lease auctions. Roughly 5.4 million acres, or about a quarter of all acreage offered by the US Bureau of Land Management, received bids during that time.

Sources: BLM (2014); BOEM (nd); Haile, Hendricks and Porter (2010).

Relationship between cash bidding and taxation/royalty arrangements

Besides being a mechanism to allocate tenements, cash bidding can also serve as an upfront taxation/royalty mechanism. In the absence of other taxes and royalty payments and in a competitive environment, explorers will be willing to pay an amount up to the expected cash equivalent of the resource rent for a given tenement (Hogan 2003; Leland 1978).³ Therefore, pure cash bidding effectively acts as a tax on resource rents (Hinchy, Fisher and Wallace 1989).

However, fully replacing an output-based royalty scheme with an upfront lump sum payment can undermine the efficiency advantages of cash bidding. When a site initially considered to be of low prospectivity (with an accordingly low winning bid) subsequently turns out to generate windfall returns, governments may be strongly tempted to impose special taxes on profits. The more severe the perceived risk of a change in government policy, the greater the distortion for exploration incentives, and the lower the cash bids submitted by companies for tenements (Hinchy, Fisher and Wallace 1989).

If cash bidding is used, a hybrid arrangement that retains the royalty or rent-based tax regime may be more suitable, as recommended by Henry et al. (2009) (and by earlier researchers such as Hinchy, Fisher and Wallace 1989). In that case, bids submitted by prospective explorers would be lowered by the expected value of the taxes or royalties applicable to the project (Leland 1978). The combination of cash bidding and rent-based taxes currently applies to the Australian Government's offshore petroleum regime for the four offshore petroleum tenements allocated by cash bidding in 2014.

While combining cash bidding with other taxes or royalties may overcome sovereign risk issues, assessing the efficiency of such a system is more complex. It is possible that a combined system may operate more effectively than either pure cash bidding or pure reliance on royalties.

Allocative efficiency advantages

Under cash bidding, gas companies with the greatest expertise, knowledge and capacity to manage risk and uncertainty will tend to be those who will submit the highest bids for tenements and obtain resource rights (Willett 2002). Cash bidding does not distort exploration or investment decisions. The payment of an upfront cash bid is disconnected from these activities, because it is a sunk cost when subsequent decisions relating to the tenement are made (ACIL Tasman 2012; Willett 2002). In order for cash bidding to facilitate an improvement in efficiency however, the tenements subject to cash bids would need to be free of distorting mechanisms — particularly conditional and limited tenure, which can create incentives to undertake inefficiently early exploration.

³ Assuming investors are risk averse, the cash equivalent (or certainty equivalent value) is equal to the expected net present value of a project, less a risk premium (Hogan 2003).

Criticisms and design challenges

There are a number of issues and practical design challenges to be resolved for successful implementation of cash bidding. If these are not addressed, bids submitted may be lower than is desirable, and the community will not derive the maximum benefit from the resource rent.

Designing an auction system that promotes efficient outcomes

One issue associated with the cash bidding system is the requirement to design the auction method. At a minimum, this involves an administrative cost, which in some cases could outweigh the efficiency gains of the mechanism.

The features of the auction mechanism will also influence outcomes, both in terms of achieving a sale, when it is efficient to do so, and in securing the correct price from the highest value user. There are many auction formats of varying complexity to choose from (box 4.3).

No single auction method is likely to be suited for all circumstances and tenements. ACIL Tasman (2012) has suggested that when competition amongst bidders is expected to be weak, or when lots are of low ex ante value, the first price, sealed bid system is likely to be the best option. By contrast, when competition for tenements is strong, or bidders lack information, one of the more complex combination auction mechanisms will be more suitable. Increasing the quality and quantity of pre-bid data can alleviate informational problems. Basic geological mapping functions undertaken by government agencies can yield useful information for gas companies, although such data are often made available after a time lag. For example, basic exclusive data for offshore petroleum tenements in Commonwealth waters are often released two to three years after acquisition by an explorer (ACIL Tasman 2012).

Once a cash bidding system is operational, the administrative and compliance costs would likely be lower than work program bidding and first come first served mechanisms. The allocation criterion is clearly defined and simple, and limits the scope for bureaucratic or ministerial discretion that is likely to be present in the alternative allocation mechanisms (ACIL Tasman 2012; Willett 2002).

Risk of selecting 'unfit' operators

One of the reasons for governments' support of non-financial criteria when allocating tenements is that it can provide some assurance that the licensee is capable of and has committed to managing the environmental and public health risks of their activities. Screening of applicants could reduce the burden on the agencies that undertake subsequent monitoring and enforcement of compliance with environmental and public health regulations, and consequently lower the risks of any adverse effects.

Box 4.3 Examples of auction formats and their application

There are a number of different auction designs that authorities responsible for administering allocation rights may choose to utilise. Auctions have been used for purposes as diverse as allocating resource tenements, public infrastructure, communications spectrum, selling treasury securities in financial markets, and even in environmental management. In the case of the latter, for example, the Victorian Government uses an auction mechanism called BushTender to improve native vegetation on private land.

Sealed bid

Bidders simultaneously make confidential bids to the seller, with the highest bidder being awarded the tenement and paying the value of their bid. This auction system is used to allocate offshore petroleum licences in the United States, as well as Commonwealth offshore petroleum tenements for which cash bidding is employed.

To reduce the problem of the ‘winner’s curse’ the auction can be modified to a second-price sealed bid auction (also known as a Vickrey auction). (Winner’s curse could arise due to uncertainty about the value of the tenement, where the most optimistic bidder, potentially paying more than its market value, would win the auction.) In such auctions, the tenement is awarded to the highest bidder at the price offered by the second-highest bidder. Possible shortcomings of the second-price sealed bid auction include the potential for collusion between bidding parties, as well as the use of shills to force the auction price above the second-highest bidder’s valuation.

Open auctions with an ascending or descending price

Auctions are conducted interactively, with bidders present (either physically or electronically). In ascending price auctions, often called English auctions, the tenement price is raised until only one bidder remains. The United States Forest Service uses open auctions (in addition to first price sealed bid auctions) to sell timber rights.

In descending price auctions (also referred to as Dutch auctions), the seller lowers the price of the object from some initial value, and stops when the first bidder agrees to pay a particular price. One prominent current application is in the sale of US Treasury securities.

Sources: ACIL Tasman (2012); Department of Industry (2014b); DEPI (2014); Hendricks and Porter (2014); Mann and Klachkin (2014); Rothkopf, Teisberg and Kahn (1990).

As discussed earlier, work program bidding arrangements incorporate various objectives, which are not always transparent (such as the process for deciding between ‘equally deserving’ applicants for petroleum exploration licences in Commonwealth offshore waters), and which often focus on considerations that are not related to managing the environmental and health risks of gas exploration and production. Even if the arrangements are effective in reducing those risks, there are trade-offs to be considered. Specifically, work program bidding can favour incumbents and entrench their position, reducing the capacity of new entrants to compete because they become relatively efficient at completing the work program assessment process, due to experience gained in submitting bids.

Nevertheless, some applicant screening may still be required — whether through requiring participants to add the environmental and health risk management undertakings to their

bids, or by setting a common standard to be met by participants as a pre-condition of participating in the tender. In Queensland, for example, gas companies are required to meet environmental and other tenure approval requirements before tenure is granted. To be effective, the screening criteria would need to be transparent and directly aligned with the relevant objective of maximising the net present value of the resource rent over time.

Number and strength of bids in auctions

A common objection to cash bidding for resource tenements is that auctions might attract little interest, resulting in low bids for potentially highly valuable resource tenements.

One of the reasons why tenements may attract relatively few bids is if the rights associated with them are highly conditional. The limited duration of rights, relinquishment requirements, and mechanisms such as use it or lose it, may all affect the timing and expenditure required for exploration and production activity. Such conditions reduce the value of the tenement to any potential explorer. As a result, explorers may lower their bids for tenements, or decline to bid altogether. By providing key information about the nature of the land being allocated, the Government can better inform the market on its prospects and hence condition the bids.

Administrative costs of participating in a tender are another important consideration. For example, the Commission previously found that an Australian government tender for water rights in the Murray-Darling basin involved material costs and delay for participants. This was despite the rights in question being relatively homogeneous and actively traded in markets (PC 2010). Bidding costs were also a feature in the Commission's public infrastructure inquiry (PC 2014b).

Nevertheless, as experience with cash bidding grows, and parties become more familiar with its institutional features, greater understanding of the process could lead to more bidding activity, and by a wider range of explorers. Subsequently the rules and applications for cash bidding could be adjusted if necessary. This process would be assisted by the adoption of transparent processes for cash bidding by governments, and the avoidance of arbitrary changes to tenement conditions after an auction has been held, when the owner is undertaking exploration or production. Gas companies would have greater confidence in the integrity of the cash bidding system, and be more inclined to participate.

Cash bidding and competition

There has been some criticism of cash bidding on the grounds that smaller explorers may be disadvantaged due to limited funds, preventing them from bidding, or undertaking exploration activity in the event of making the winning bid (APPEA 2012).

However, it is not clear how the requirement of a lump sum bid could create a *new* barrier to entry to smaller companies. As discussed, even in a first come first served arrangement,

if more than one company is interested in acquiring the tenement, unless the decision is made by ballot, some form of a competitive process is required to determine the winner. (In assessing bids, jurisdictions also typically consider the technical expertise of companies proposing work programs.) The difference offered by a cash bidding system is that in those situations, the decision is less opaque and is based on a simpler and more objective criterion. Provided a bidder offers a price that is reasonable for the tenancy being offered, finance should be readily available.

Further, large companies may not always have access to greater financial resources than smaller companies for all tenements and projects. Smaller companies can use structures such as joint ventures if they feel they have insufficient funds to match the bids of larger companies. More importantly, a company, irrespective of its size, would not bid beyond its valuation of the tenement in question. The objective of gas companies — whether small or large — is to maximise the value of the resource rent, and this objective is not served by making inflated bids for tenements.

The Association of Mining and Exploration Companies argued that cash bidding:

... simply allows the companies with the access to the largest amount of cash to warehouse tenements ... cash bidding tenure process enshrines a system where those companies with the largest cash reserves win the most prospective tenure, not the company most likely to develop any discovery. (AMEC 2013, p. 10)

As discussed above, the timing and magnitude of gas exploration and production need to be seen in the context of the incentives present in the market. What may appear as unjustified hoarding of gas reserves may simply reflect commercial behaviour based on the producer's risk preferences, production costs, and the current and expected future prices of gas. The rationale for larger companies to have a greater propensity to 'hoard' than smaller companies is also unclear — if there were some market advantage to be gained by hoarding, this would be independent of company size, as it would be motivated by the desire to maximise profits.

Learning from current cash bidding systems

In sum, allocating gas tenements via cash bidding has theoretical appeal, when compared to the work bidding programs currently in place. However, there are some practical challenges in designing an effective scheme that delivers benefits that outweigh the cost of implementation. These include the need to select an auction mechanism and finding the right balance between upfront and ex-post payments by the licensee. There may also be a case for a transparent and robust arrangement for screening applicants for their capacity to manage environmental and public health risks.

The Australian and Queensland Governments have recently introduced cash bidding schemes for petroleum licences. There is merit in observing the operation of those schemes to assess their efficiency, and in drawing lessons on system design and the scope for their broader application, as well as learning from the successful operation of cash bidding regimes overseas.

5 Managing conflicting land uses

Key points

- The rapid growth of the gas industry and its progressive encroachment onto private land has exposed conflicts between the existing landholders, local communities and the gas industry.
- A statutory provision for compensation is the best mechanism for addressing the effects of gas activities on the landholder. This is in place in all jurisdictions.
 - There is, however, generally no provision for compensation for adverse community effects, notwithstanding that in some cases environmental impact statement processes can allow for this.
- There is scope for improvements to legislated compensation criteria to better reflect the costs to landholders from negotiating land access agreements and from the decline in the value of their properties.
- There is scope for measures to reduce the costs of negotiating land access agreements including: the development by industry and landholder groups of template agreements and guidance material; and, if the costs are reasonable, the publication by governments of compensation benchmarks.
- Community concerns about the environmental and public health risks of coal seam gas (CSG) activities have led to CSG moratoria in Victoria and New South Wales.
 - The expected benefits of the moratoria must be weighed against their expected costs — higher gas prices for users and reduced royalty and taxation revenue for governments.
 - Sound risk management does not equate to eliminating all risk. The scientific evidence suggests that the technical challenges and risks can be managed through a well-designed regulatory regime, underpinned by effective monitoring and enforcement of compliance.
 - Gas companies should also provide environmental assurance and insurance proportionate to the risk of their activities.
- If governments seek to impose moratoria or revise land planning protections to favour existing land uses, a transparent consideration of the costs and benefits (including the loss of royalties and the implications for taxation revenues) should be undertaken.
- Government redirection of royalties back to communities hosting gas activities, to emphasise that communities can benefit from exploration and production, has questionable equity implications and may lead to poor quality investment of public funds.
- Some members of the gas industry have had a poor early record of dealing with landholders and local communities. More recently, some companies have increased their efforts to obtain a 'social licence to operate'.
 - Further thought by explorers and producers on early engagement directly with communities, rather than simply on compensation for landholders, is needed.
 - A well-designed voluntary industry-wide code of practice for community and landholder engagement may improve outcomes.
- There may be merit in an independent agency with powers to collect and disseminate information, advise government and directly engage stakeholders to resolve land use issues.

The rapid growth of the gas industry and its progressive encroachment onto private land has exposed some sharp conflicts between existing landholders, local communities and the gas industry. This chapter examines some of the policies that have been adopted by governments to manage the effects of gas exploration and production on other parts of the community.

In broad terms, exercising the rights for onshore gas exploration and production can generate two types of land use conflicts — the effects on the landholder hosting the activity, and broader economic, amenity, social and environmental effects on the community. Australian governments have generally considered this dichotomy in their policies and the same approach is followed here.

5.1 Managing the effects on directly affected landholders

In Australia, the Crown owns the onshore (and coastal water) gas resources and can grant resource exploration and production rights to gas companies (chapter 4). Exercising the exploration and production rights often requires access to private land and existing landholders generally do not have the right to refuse such access.

Most of the land for which access is being sought is currently used for agriculture, and gas exploration and production activities can generate a number of adverse effects (or negative externalities) for existing landholders, especially during the pre-production phase. These include:

- loss of the use of land occupied by the exploration and production infrastructure, such as wellheads and roads
- severance effects — the productivity and value of the land which is not occupied by gas production infrastructure can be affected
- damage to environmental resources, such as soil, water and trees, as well as to property and improvements on the land, such as gates and fences
- general disruption and loss of amenity arising from the noise, dust and visual disturbance (Fibbens, Yak and Williams 2014).

Generally, the most substantial disruption to the landholder occurs in the early development stages, when the wells are being drilled and other infrastructure is installed (Kerr 2012). However, some externalities can persist for the duration of the exploration and production activity and beyond.

While these effects arise from exploration and production activity for both conventional and unconventional gas, disruption to existing land uses can be particularly noticeable in the case of coal seam gas (CSG) activities. CSG activities involve a more expansive use of

the land than conventional gas exploration and production, with multiple wells typically being drilled, including using horizontal drilling technology.

In all jurisdictions, the primary mechanism for addressing those issues is the landholder's statutory right to compensation from the gas company. Compensation is the best mechanism for the task because it enables outcomes that are customised for particular circumstances, the relevant parties are few and easy to identify, and the costs incurred by landholders are *relatively* easy to quantify. It also leverages off the incentives and information of the parties to determine the highest value use of the land through negotiation between the landholder and the gas company accessing the land (PC 2013b). Nevertheless, there is scope for improvements to legislated criteria for landholder compensation and for measures to reduce the costs of negotiating land access agreements.

A sound compensation regime that helps align the relevant interests will best support the joint incentive to maintain a cooperative rather than adversarial relationship, and can reduce the costs incurred in negotiating such access agreements.

The role of statutory compensation provisions

The legislation in every jurisdiction lists the 'heads of compensation' which outline what effects a landholder can be compensated for by the gas company. The heads of compensation differ across jurisdictions and there has been some debate as to what constitutes a reasonable compensation for the landholder, as well as how this should be presented in statute.

Decline in the market value of the landholder's property directly reflects the cost of hosting gas activities

Under the existing allocation of property rights, compensation serves the purpose of remedying the damage to landholders from the exercise of exploration and production rights. The damage can take many forms, and it is challenging to develop an exhaustive list that covers all circumstances. However, one objective and direct measure of the economic cost of gas activities to the landholder that encompasses the different types of damage is the decline in the market value of the landholder's property (land and any improvements). The market value reflects the highest value uses of the land with and without the gas activities.

Statutory provisions are typically just a guide for negotiations

While statutory heads of compensation provide a benchmark for compensation negotiations, they will only be applied prescriptively if negotiations break down and the parties engage in arbitration or litigation. In most cases, negotiating parties would seek to achieve a mutually acceptable outcome well before that. In Queensland, over 4500 conduct

and compensation agreements were signed by landholders and gas companies between 2011 and 2013 (APPEA 2014c), while only a handful of matters proceeded to the Queensland Land Court.¹ A review in New South Wales found that there have been no arbitrations for land access agreements for petroleum exploration between 2011 and 2014 (Walker 2014).

Given that the parties face additional costs if the matter proceeds to arbitration or litigation the compensation amount negotiated privately could differ from what is provided for in the legislation. Some of the large gas producers, such as Santos (box 5.1) and AGL Energy,² have developed compensation policies that exceed what is required under statutory provisions.

In addition, in 2014 Santos and AGL Energy signed The Agreed Principles of Land Access with landholder representatives NSW Farmers, Cotton Australia and the NSW Irrigators Council. The Principles state that Santos and AGL Energy will not enter the land for drilling operations if the landholder objects (NSW Government 2014a).

Box 5.1 Santos' landholder compensation arrangements

Santos has developed a standard compensation offer for gas exploration and production activities, which it makes to landholders in New South Wales.

At the exploration phase, the offer consists of:

- in the first year, 120 per cent of the value of the land utilised by Santos (as determined from the current rates notice)
- in subsequent years, 60 per cent of the value of the land
- a \$30 000 annual fee for site upkeep and monitoring services provided by the landholder.

At the production phase, the offer comprises:

- in the first year, 120 per cent of the value of the land utilised by Santos
- in subsequent years, a share of an incentive fund, the size of which is linked to Santos' royalty payments associated with private land within a production licence. Santos estimated that payments would be in the range of \$20 000–\$40 000 per property per annum
- a \$30 000 annual service fee for upkeep and monitoring services.

Source: Santos (2013a).

¹ The Court's annual reports state that under the relevant legislation there were no new appeals in 2012-13, and that between 2010-11 and 2012-13, 6 appeals were finalised (Land Court of Queensland 2011; 2012; 2013).

² For example, AGL Energy (nd) is offering compensation for landholders' time at the agreement negotiation stage and over the life of the agreement, which it is not required to do under legislation.

An informed and low cost negotiation process is crucial

The provisions outlining property and compensation rights should leverage off the incentives of the gas industry and landholders to determine the highest value use of the land through negotiation. Two factors are particularly important.

First, the parties should have certainty as to who is entitled to compensation and what costs can be recovered.

Second, it is imperative that negotiations are underpinned by the best available information about the potential effects of the proposed gas activities. There is inherent uncertainty (as well as some misinformation) about some of the effects of gas exploration and production activities on the landholder. The exploration process is influenced by many factors and it can be difficult to predict at the outset what activities would need to be carried out by the gas company, as well as their duration. Thus, it may be desirable to provide for review of a compensation agreement between the gas company and the landholder if there is a material change in the circumstances or new knowledge about the costs of the gas activities on the landholder.

A separate issue relates to the capacity of the parties to process and evaluate information to underpin their decisions. The Commission has previously found that land access negotiations for resource exploration typically involve a large volume of technical, legal and financial information and require some expertise in undertaking negotiations. It concluded that there were asymmetries in the availability of information and negotiation experience between gas companies and landholders.³ Thus, the Commission recommended on both efficiency and equity grounds that resource exploration companies be required to compensate landholders for reasonable costs of professional advice (PC 2013b).

Assessment of statutory compensation provisions

There are some shortcomings in the current statutory compensation provisions across jurisdictions (table 5.1).

In two jurisdictions — Victoria and Western Australia — a landholder is not explicitly entitled to compensation for the cost of obtaining professional advice. In New South Wales, compensation is only available for legal, but not financial or other expert advice.

Two states — Victoria and Queensland — explicitly recognise a decline in land value as a basis for calculating compensation. However, in both cases, this is one item on a list that includes other factors, such as: deprivation of possession; effect of severance of the land from other land owned by the landholder; and damage to the land and improvements.

³ Subsequent research by Sinclair Knight Merz (SKM 2013a) in Queensland showed that the legal costs of arranging a compensation agreement could be substantial. Petroleum companies reported that for ‘high impact advanced activities’ the fees they paid for their own advice were in the range of \$10 000–\$50 000.

Those other effects would ordinarily be captured in the change in market value of the land and there is no clarity on how this overlap should be reconciled. If all of the factors were simply aggregated, there is a possibility of double counting some of the costs imposed on the landholder. In Victoria, the picture is further complicated by a statutory limit of \$10 000 on compensation for loss of amenity and an allowance for a 10 per cent uplift to the overall payout for ‘intangible and non-pecuniary disadvantages’.

Table 5.1 Statutory compensation provisions for land access
Selected jurisdictions

	<i>NSW</i>	<i>Victoria</i>	<i>Queensland</i>	<i>SA</i>	<i>WA</i>
Pre-requisite for access to land for exploration	Land access agreement	Consent of landholder or land access agreement	Notice for low impact activities Land access agreement for high impact activities	Notice for low impact activities Land access agreement for high impact activities	Compensation agreement
Landholder right to compensation	Yes	Yes	Yes	Yes	Yes
Decline in land value	No	Yes	Yes	No	No
Legal and professional costs	Yes, legal costs up to limit	No explicit provision	Yes, accounting, legal and valuation	Yes, reasonable negotiation costs	No explicit provision
Review mechanisms post agreement	Yes, parties can apply for reassessment	Yes, claim for additional loss can be made later	Yes, optional clause in agreement for material change in circumstances	No explicit provision	Yes
Compensation for neighbours?	Yes	Yes	Yes	No explicit provision	Yes

Sources: Petroleum (Onshore) Act 1991 (NSW); Mineral Resources (Sustainable Development) Act 1990 (Vic); Petroleum Act 1998 (Vic); Petroleum Act 1923 (Qld); Petroleum and Gas (Production and Safety) Act 2004 (Qld); Petroleum And Geothermal Energy Act 2000 (SA); Petroleum and Geothermal Energy Resources Act 1967 (WA).

In other jurisdictions, compensation is available for prescribed factors, which could create risks of under-compensation if some factors that affect property values are omitted. For example, the legislation in Western Australia and New South Wales recognises the severance effects of gas activities on the land not occupied but the gas company, but does not provide for compensation for other costs, such as loss of amenity for the landholder.⁴

In most jurisdictions, compensation is also available to other landholders that suffer damage to their properties as a result of exploration or production activities.⁵

Compensation for the economic cost to the landholder is different to sharing in the benefit

Some stakeholders (for example, the Victorian Farmers Federation (VFF nd)) have proposed that in addition to being compensated for any loss, landholders should have a right to additional payments for the use of their land. In 2014, the NSW Government stated in its Gas Plan that ‘legislation will be introduced to ensure that landholders share in the financial benefits of gas exploration and production’ (NSW Government 2014b, p. 6). The Independent Pricing and Administrative Tribunal (IPART) has been asked to provide advice on benchmark compensation rates for landholders, taking account of (among other things) ‘the economic benefits over the lifecycle stages of a project’ (NSW Government 2015b, p. 2).

However, such approaches may allocate some of the benefits associated with the property right in the gas resource (owned by the Crown and leased to the gas producer) to the landholder. In doing so, they would clash with the current allocation of the property rights for all subsurface resources.

In addition to the equity implications of shifting the benefits of resource ownership from the broader community to specific landholders, there are risks for efficiency. While the question of how the rents from gas activities are shared between the stakeholders is not directly relevant for efficiency, any *reallocation* of the benefits accruing from existing property rights creates strong incentives for rent-seeking and other unproductive behaviour by all affected parties. Any transition to a new allocation of benefits from gas activities would also be likely to generate some uncertainty and disruption for all parties. Poorly designed policy, intended to favour landholders could add to costs on both sides, while not addressing landholder and community concerns.

A substantial change in compensation settings for gas activities in any jurisdiction could also set a precedent for other jurisdictions, as well as for other resource extraction

⁴ The concept of ‘injurious affection’ is recognised in compulsory acquisition laws of many Australian jurisdictions. Landholders have a right to compensation not only for the land they lose, but also for any loss on the land they retain that arises from the act of acquisition (Fibbens, Yak and Williams 2014; French 2013).

⁵ In addition to any statutory compensation provisions, landholders would also have access to Common Law relief under the tort of nuisance.

activities. Thus, a seemingly confined change to compensation arrangements could have significantly broader implications for governments, the gas and other resource industries, and the broader community.

Improvements to the process of arranging land access

Template compensation agreements and negotiation guidance materials

The time and resources spent by gas companies and landholders on the development and review of compensation agreements could be reduced through the development of template agreements that set out the key aspects of the conduct and compensation to be negotiated by the parties. Greater uniformity of agreements would also facilitate price discovery and benchmarking efforts and make such information more useful to the parties, while addressing expectations.⁶

The Queensland Government provides a generic conduct and compensation agreement for landholders and resource project proponents, which addresses a range of factors, including: parties obligations; access conditions; rehabilitation of the land; insurance; and compensation (Queensland Government 2010). In New South Wales, the Department of Trade and Investment, Regional Infrastructure and Services (NSW DTIRIS 2013) has published a generic template agreement for non-gas mineral exploration.

It is not evident that governments must play a significant role in developing templates. The peak bodies representing the agricultural land users and the gas industry have the incentives and the capacity to allocate resources to the task. They are also likely to be better informed about the needs of their constituents than governments when formulating the content of a template agreement. Notably, the original standard template developed by the Queensland Government was deemed too lengthy and legalistic by stakeholders (SKM 2013a).

The provision to landholders of general guidance material for negotiations could also be beneficial. AgForce Queensland, with support from the Queensland Government, the Queensland GasFields Commission and resource industry groups has developed a CSG negotiation workbook and is running workshops to inform landholders about the key aspects of negotiation and land access laws. It has reported strongly positive feedback from landholders about this initiative (pers. comm., 30 January 2015).

Transparency on compensation amounts and agreement particulars

Other reviews (SKM 2013a; Walker 2014) have noted that there is very limited information in the public domain on the content of privately negotiated land access and

⁶ Nevertheless, some customisation would still be necessary to reflect different individual circumstances.

compensation agreements. Some landholder groups have suggested to the Commission that greater transparency on previous land access and compensation agreements could assist landholders and gas companies and anchor expectations.

Some gas companies are beginning to disclose their compensation policies (for example, the Santos offer to New South Wales landholders discussed above). Generally, transparency from the gas companies about their compensation policy could lead to lower negotiation costs and also help address any perception that they take advantage of more vulnerable landholders.

There have also been moves by policy makers to improve transparency. In Queensland, the GasFields Commission was established in 2013 with the aim of managing the coexistence issues between rural landholders, regional communities and the onshore gas industry (box 5.2). The GasFields Commission was tasked with developing a register of conduct and competition agreements and providing de-identified information to landholders. The Commission can issue mandatory information requests for this purpose.

Box 5.2 Queensland GasFields Commission

The GasFields Commission was established on 1 July 2013 as an independent statutory body (*GasFields Commission Act 2013*) tasked with managing and improving coexistence among rural landholders, regional communities and the onshore gas industry. The Commission has six portfolios, which cover issues in science and research; water management; local government and infrastructure; community and business; land access; and gas industry development. Commissioners have been appointed for their expertise in each of those fields.

The Commission operates at the interface of state and local governments, the gas industry and local communities and has a number of powers and functions, including:

- making recommendations to the Government on regulatory best practice and amendments to existing regulations
- advising the Government about the ability of landholders, regional communities and the onshore gas industry to co-exist within identified areas
- convening parties to resolve issues
- collecting information
- publishing educational materials.

Source: GasFields Commission Queensland (nd).

As noted earlier, in New South Wales, under the Gas Plan, IPART has been tasked with collecting information on agreements to develop compensation benchmarks.

At this stage it is too early to assess the merits of these approaches. There would be some costs, such as the administrative and compliance costs of collection. Confidentiality considerations are also important, although they should not be used as a blanket excuse to avoid disclosure. In addition, there may be implementation challenges in making such information relevant and useful. The land access agreements are not uniform in form or

content and are influenced by many factors, including the type of, and current operations on the land (Letizia, Roettgers and Cooper 2013).

Nevertheless, the Commission is supportive of efforts to reduce the transaction costs and improve transparency for landholders and gas companies in negotiating such agreements. Provided the above costs are reasonable, there is scope for measures such as the publication by governments of compensation benchmarks.

5.2 Managing the effects of gas exploration and production on the broader community

Governments have drawn on a mix of policies to address the effects of the gas industry on the broader community, including:

- environmental and health and safety regulations, both general and specific to the gas industry
- land planning policies
- incentive schemes to compensate affected local communities
- policies to facilitate community engagement by the gas industry.

The policy landscape in each jurisdiction is very complex and the Commission has not attempted a comprehensive assessment, electing instead to focus on several policy ‘hotspots’.

Regulatory responses to environmental and public health concerns

Over the past decade, most of the debate and regulatory policy developments in the eastern Australian gas market have centred around managing the environmental and health and safety effects of the exploration and production of CSG.

There have been strong community concerns that the water-intensive nature of CSG exploration and production would deplete groundwater resources and have adverse consequences for water tables. Some members of the community are also concerned about the risks of groundwater contamination, the disposal of produced water and other by-products, as well as the subsequent rehabilitation of the land.

These considerations have prompted the NSW Government to introduce a moratorium on new CSG exploration licences and on CSG production in water catchments. The NSW Gas Plan subsequently announced the extinguishment of current exploration licence applications and government buyback of existing gas exploration licences. The hold on new exploration licences will remain until the Government introduces a new ‘Strategic Release Framework’ (NSW Government 2014b).

In Victoria, a moratorium on all hydraulic fracturing and new onshore exploration licences has been in place since 2012. A further hold on all exploration drilling for existing licences was added in 2014.

The jurisdictions with established CSG operations — Queensland and Western Australia — as well as South Australia, have proceeded with relatively smaller changes to their regulatory settings. Nevertheless, those jurisdictions have also not been immune from pressure to curtail or stop CSG activities. Some local councils across those states (for example the Douglas Shire council in Queensland and Coorow in Western Australia) announced themselves to be CSG free or called for a moratorium on CSG activities (Egan and Sewell 2014; Perpetch 2014).⁷

Moratoria are not costless

Concerns about the environmental and public health effects of CSG activities are undoubtedly important. There are several tools through which these concerns could be addressed — moratoria are but one of them. However, whatever policy tool is implemented, the expected benefits from reducing the environmental and public health risks from CSG activity should be assessed against the expected costs to the gas industry, gas users and the Australian community as a whole.

Estimating the costs of the moratoria is extremely difficult, as the costs could be influenced by many factors. Important considerations include: liquefied natural gas (LNG) prices in the Asia-Pacific market; characteristics of the domestic demand for gas on the east coast of Australia; the costs of gas production from the supply sources affected by the moratoria, and the costs of alternative sources of supply on the east coast. A key source of uncertainty is the moratoria themselves, as they are preventing exploration activity that could provide a measure of the size and commercial viability of affected gas reserves. Estimates of expected production costs and well deliverability fluctuate considerably on the back of limited, and in many cases, nonexistent data. Nevertheless, the underlying mechanisms through which the eastern market can be affected by the imposition of moratoria do not change. The Commission has modelled some hypothetical CSG moratoria scenarios for New South Wales and Victoria that illustrate those mechanisms. The full modelling results, including the sensitivity analysis on some key assumptions are presented in appendix C (available online).

While the moratoria on CSG production in New South Wales and Victoria address concerns about the potential risk to the environment and public health, they also impose a constraint on the supply of gas in the eastern Australian gas market and may necessitate the development of more expensive sources of supply. Where this occurs, a cost will be

⁷ While local councils typically do not have powers to directly block exploration or production activity approved by state governments, they have approval powers over ancillary developments that a CSG project is likely to need. However, State Governments generally have the capacity to overrule local councils that refuse development approvals (AAP 2014).

imposed on some or all of the gas industry, domestic gas users and the broader community. The form that these costs take and their distribution depends on a number of factors and could change over time. Where moratoria reduce gas production but do not affect the quantity of gas exported (for example, where all export commitments are already locked-in through long-term contracts) the effect will be largely felt by gas users within the eastern Australian gas market through higher prices.

In the longer term, reductions in production resulting from the moratoria could be reflected in lower gas supply volumes (including for export) and, as a consequence, reduced royalty and taxation revenue. The gas industry and the broader community would bear the brunt of those costs. The costs would be greater if LNG prices are high enough to create the incentive for a significant increase in production on the east coast, but gas producers are prevented from doing so by the moratoria.

The costs of moratoria will be felt for some time

There is typically a delay of 3–6 years between investments in gas exploration and production and the actual supply of gas to users, and such investments have large upfront costs. This means that moratoria could lock in some higher cost production and the effects will likely continue to play out for several years after the moratoria are lifted. The costs would be magnified if there is uncertainty about the duration of the moratoria, as this may lead to gas and pipeline companies holding off on investment decisions until they receive a clear signal about future policy from the government.

Moratoria could encourage wasteful behaviour

To the extent that moratoria (or a threat of them) are driven by community pressure on their respective governments, they could also distort the incentives of the gas industry, landholders and local communities. For example, they could encourage gas companies to secure landholder and community support through increased financial contributions, where the issue may be best resolved through a sound, transparent and credible regulatory framework. In effect, moratoria could increase pressure for other actions by stakeholders that may not necessarily be motivated by the interests of the broader community.

The science is developing, but some uncertainties remain

In recent years there has been a substantial research effort to fully understand and be able to predict the environmental and health effects of CSG activities.⁸ However, there are still uncertainties about some of the long-term effects of those activities. There are gaps in

⁸ For example, the GasFields Commission Queensland (2013) collated the water-related science and research activities in relation to the Queensland CSG industry. It reported on 188 projects carried out by universities, government agencies and CSG proponents, in addition to the technical assessments undertaken by CSG proponents as part of their approval processes.

baseline data, hindering effective monitoring, and there is also as a need for more information on the cumulative impacts of multiple activities on the land (NSW Chief Scientist and Engineer 2014).

Werner et al. (2015) reviewed the literature on the human health effects of unconventional gas development, identifying over 100 relevant studies published between 1995 and 2014 around the world. The researchers concluded that the current scientific evidence that showed adverse health effects from unconventional gas development lacked methodological rigour. However, they also found that there were gaps in knowledge, particularly on the long-term health effects and that the evidence did not rule out adverse effects.

Community groups have drawn on several incidents as evidence of the environmental and health risks of CSG activities in Australia. Some of these, such as for example a spill at a CSG plant owned by Santos in the Pilliga Forest in New South Wales have been acknowledged by the industry, who nevertheless argued that these are isolated events with low likelihood of environmental harm (Santos 2014a). In another case, a landholder reported the Condamine River ‘bubbling’ methane in 2012. An investigation by the Queensland Government could not identify the causes of the gas seeps, but concluded that they posed no risk of harm to human health or the environment (DNRM 2012).

One of the more high profile cases involved an outbreak of ill health amongst communities living in gas fields near Tara and Kogan (both in Queensland). Symptoms included daily headaches, epistaxis (nose bleeding), rashes, nausea, eye irritation, sensation of metallic taste and respiratory problems. However, an investigation undertaken on behalf of the Queensland Department of Health found no clear link between emissions from CSG activities and health complaints from residents (DoH 2013).

The NSW Chief Scientist and Engineer, acknowledged the scientific uncertainty but noted:

CSG extraction and related technologies are mature and Australia is well equipped to manage their application ... The independent petroleum engineering, geological and geophysical experts advising the Review consider that such technologies (including fracture stimulation and horizontal drilling technologies), with appropriate safeguards, are suitable for use in many parts of the sedimentary basins in NSW, noting that drilling in any new location is, to an extent, a learning-by-doing activity as there will always be local geological attributes specific to an individual resource development. (2014, p. 9)

Sound risk management does not equate to eliminating all risk

Some stakeholders (for example, the Australian Medical Association (AMA 2013) argue that CSG activities should not proceed on ‘precautionary principle’ grounds, due to scientific uncertainty about their effects. The National Toxics Network (NTN 2011) advocated a halt to the use of drilling and fracking chemicals, because its research showed that of the 23 commonly used chemicals only 2 have been assessed by Australia’s National Industrial Chemical Notification and Assessment Scheme.

These are not idle concerns and the uncertainty about adverse environmental and health outcomes requires governments to be cautious when determining the regulatory settings. However, no activity can be risk free, and any type of land use, including agriculture and extraction of any sub-surface resources is likely to create some environmental consequences, not all of them foreseeable at the outset.

Sound risk management recognises that there are trade-offs in reducing risk. Furthermore, the precautionary principle, which is found in some legislation, is a difficult concept to apply in policy — a level of risk that may be acceptable to one person, may be less so to another. Further, the avoidance of a particular risk on the basis of the precautionary principle may lead to a more significant risk elsewhere causing greater harm (such as shifting activities to locations with less intensive monitoring and regulation). Crucially, the burden of regulation and supervision should be consistent and coherent with the risks of the activity. This is not just an issue of equity. Applying inconsistent risk management standards across activities could lead to distortions in favour of higher risk activities that are subject to a lower level of regulatory oversight.

There is some evidence that CSG activities may be required to meet a higher standard than other activities. For example, the NSW Chief Scientist and Engineer noted:

Many industry and community groups have alerted the Review to varying legislative and regulatory regimes for things similar to those relating to CSG extraction. Legislation and regulation covering the construction of wells and production of gas from coal seams as part of coal mining activities is less stringent than that for CSG production. Similarly a 2km buffer zone approach has been introduced for CSG extraction, but no such zone is in place for conventional gas or other types of unconventional gas extraction. (2014, p. 8)

In the context of stakeholder attitudes, the NSW Chief Scientist and Engineer also observed:

Certain processes such as fracture stimulation ('fracking') and, to a lesser extent, horizontal drilling, are of particular concern in the context of CSG although the use of these techniques in other industries (underground water access in the case of fracture stimulation and infrastructure provision in the case of horizontal drilling) is more accepted. (2014, p. 7)

A more general example of regulations allowing a higher level of risk and uncertainty for other activities than what is advocated for CSG can be gleaned from the Commission's review of Australian chemicals and plastics regulations (PC 2008).

Some of the support for moratoria is driven by opposition to fossil fuels in general

A number of stakeholders (for example, Lock the Gate (nd); Public Health Association of Australia (PHAA 2013)) oppose the CSG industry because growth of a non-renewable resource would delay the transition to renewable fuel industries in Australia and lead to increased greenhouse gas emissions in the long term.

Abstracting from the question of what is the efficient climate change policy for Australia, this argument fails to fully consider the likely market response to regulatory restrictions on the Australian production of gas.

The competition for gas to export as LNG will affect local prices in the eastern Australian gas market (chapter 3). Adding a restriction on exploration and development of new reserves could add to pressure for an increase in the price of gas relative to substitute products, thereby further reducing gas consumption. However, the net effect on emissions is far from clear. For example, if a rise in the price of gas in the eastern market led to a substitution to electricity, then this may lead to a rise in the consumption of coal, which is currently used to produce about two-thirds of Australia's electricity (BREE 2014c). Nor is it clear that a potential reduction in the supply of gas from the east coast of Australia would lead to a greater reliance on renewable energy, or lead to an overall decline in global emissions.

The broad regulatory frameworks to manage CSG risks already exist, but monitoring and compliance must be robust

Several reviews have concluded that the risks of CSG activities can be managed through existing regulatory frameworks. In 2013, the Australian Government's Standing Council on Energy and Resources (SCER 2013c) released a National Harmonised Regulatory Framework for Natural Gas from Coal Seams. The Framework was endorsed by all Australian Governments.

The Framework is underpinned by the principle of co-existence between CSG and other land uses. It focuses on four key areas of operations, which cover the life cycle of CSG development: well integrity; water management and monitoring; hydraulic fracturing; and chemical use. The Framework identifies 18 leading practices to mitigate the potential risks of CSG activities.

In developing the Framework, the SCER examined the regulatory mechanisms across Australia that are, or can be used to manage the various risks of CSG development. One of the key findings was that the necessary regulatory frameworks already exist, although some areas may need to be adapted to comply with the leading practices. The regulatory instruments already in place include:

- mandatory environmental impact assessment and approval processes for project proponents in all states and territories, and under Commonwealth legislation
- petroleum regulations that incorporate standards and codes governing the design, material, construction, maintenance, decommissioning and rehabilitation of wells
- water planning and management regulations introduced in all jurisdictions under the National Water Initiative
- Commonwealth, state and territory and international legislation, regulation, standards and codes of practice to regulate all aspects of chemical use including workplace and

public health and safety, environmental protection, transport, handling, storage and disposal of chemicals.

The reviews by the NSW Chief Scientist and Engineer (2014) and the Victorian Gas Market Taskforce (2013a) concluded that the general regulatory infrastructure necessary for managing the environmental and health effects of CSG activities was already in place. However, both reviews identified the need for specific improvements to the regimes in their respective jurisdictions, particularly in the areas of monitoring and compliance, and environmental rehabilitation.

Adequate provisions for environmental rehabilitation are crucial

The review by the NSW Chief Scientist and Engineer (2014) stated that ensuring rehabilitation of the land on completion of CSG operations was a particular concern for the community. In part, these concerns relate to legacy issues across various extractive industries, reflecting the lower regulatory standards and scrutiny that applied in the past. The review recommended that the NSW Government develop a plan to manage legacy issues associated with CSG.

For the existing regulatory regimes, it is important to ensure that provisions requiring rehabilitation are in place and that this consideration factors in the gas company's operating decisions from the outset. Environmental insurance and assurance instruments such as environmental bonds are widely used in environmental regulation across Australia to further this objective.

The NSW Chief Scientist and Engineer (2014) found that the existing environmental insurance and assurance arrangements for CSG activities in that state were unsatisfactory, and recommended the establishment of a three layered policy of security deposits, enhanced insurance coverage and an environmental rehabilitation fund. The potential models for an environmental insurance regime for CSG activities in Queensland were also recently investigated by the Queensland Competition Authority (QCA 2014).

There is a strong case for environmental assurance and insurance instruments to apply to all gas activities (including CSG), provided the burden this imposes on the industry is proportionate to the level of risk.

In sum, the scientific evidence suggests that the technical challenges and the environmental and public health risks of gas and specifically, CSG exploration and production can be managed through well-designed and well-enforced regulation. The existing moratoria in New South Wales and Victoria impose costs and appear to place a higher risk management standard for CSG than what applies for many other land uses.

Land planning and development approvals

In 2013, the Australian Government's Standing Council on Energy and Resources released a Multiple Land Use Framework (MLUF) to guide State and Territory Governments in developing their land use policies (SCER 2013a). The MLUF specifies several guiding principles and is underpinned by the overall objective to maximise the net benefits to present and future generations from a combination of land uses which benefit the wider community, now or in the future.

The MLUF provides a sound conceptual basis for land planning policies that aim to manage the conflicts between existing land uses and the activities of the gas industry. However, the Commission has previously noted that while some jurisdictions had sound regulatory arrangements managing land use conflicts, in some cases best practice was not followed (PC 2013b).

One policy tool that could assist in accommodating competing land uses is a strategic assessment. Gas exploration and production activity tends to be concentrated in particular regions, and development approval decisions may need to reflect the cumulative effects of the projects on the region, rather than simply assessing each project on its own merits. When they are done well, strategic assessments that focus on the costs and benefits of alternative land uses at a broader regional level can assist development approval decisions (PC 2013a).

NSW Strategic Regional Land Use Policy

The NSW Strategic Regional Land Use Policy was introduced in 2012 to 'identify, map and protect valuable residential and agricultural land across the State from the impacts of mining and Coal Seam Gas (CSG) activity' (NSW Government 2015a). It was implemented through Strategic Regional Land Use Plans introduced following public consultation in 2013. The policy and plans comprise several measures, including:

- CSG exclusion zones — all new CSG activity is banned within a two kilometre buffer of existing and future residential land and within 'equine and viticulture critical industry clusters' in the Upper Hunter Region. The exclusion zones initially only applied to existing residential zones in all 152 local government areas of the state and future residential growth areas in the North West and South West Growth Centres of Sydney. In 2014, they were expanded to cover seven additional 'village areas', 'future residential growth areas' and the critical industry clusters. Currently, 2.7 million hectares are protected.
- Gateway assessment process — significant mining and CSG proposals are required to undergo an upfront scientific assessment of the impact on 'strategic agricultural land' and associated water resources before submitting a development application. The process applies to 2.8 million hectares of agricultural land which has been selected on the basis of its biophysical characteristics.

Gas and mining industry stakeholders have criticised the conceptual approach behind the policy, the evidence underpinning specific outcomes and the regulatory uncertainty that prevailed during the policy's development (box 5.3).

While the stated objective of the policy is to protect existing valuable residential and agricultural land uses, it is not necessarily consistent with maximising the value of land use, which may involve a substantial change to the status quo. The approach of identifying land to be protected purely on the basis of its biophysical compatibility with agriculture ignores the alternative, potentially higher value, uses of the land for the current and future landholders.

Ultimately, land use planning policy cannot and should not be divorced from acknowledging existing land uses. Introducing new uses on the land such as gas exploration and production will involve costs for the incumbent landholders, which may not always be outweighed by the benefit. However, policies that seek to protect existing land uses as an *a priori* objective risk generating a net cost to the community. If governments seek to revise land planning protections to favour existing land uses, a transparent consideration of the costs and benefits (including the loss of royalties and the implications for taxation revenues) should be undertaken.

Box 5.3 Gas industry's reaction to the NSW Strategic Regional Land Use Policy

APPEA (2013a) and Santos (2012) argued that the Gateway process substantially added to the regulatory burden, while the NSW Minerals Council (2012) claimed that it duplicated existing arrangements.

Metgasco's Chairman observed:

In February 2013, before we got to the drilling of our planned pilot wells, the NSW government responded to continuing anti-CSG pressure by announcing a proposed but undefined 2 kilometre exclusion zone for CSG around townships ... This was a devastating and unexpected blow to the whole industry, not just Metgasco. There was absolutely no government consultation with industry prior to this announcement. The proposed new exclusion zones covered areas with certified reserves that we had developed over the past 10 years with shareholder funds. (Metgasco 2013a)

In a different forum, Metgasco further argued:

... there is no scientific basis, nor is there any risk management justification to support the proposed 2 km exclusion zone – it is nothing more than an arbitrary, politically based imposition on the CSG industry and the more than one million NSW gas customers who rely on competitive natural gas supplies. (2013b, p. 1)

ACIL Allen Consulting in a report to AGL Energy observed:

The constraints imposed by this policy have had a significant effect on the plans and declared reserves of participants in the New South Wales CSG industry. AGL Energy has written down around 400 PJ of reserves across its Camden, Gloucester and Hunter Valley acreage with Hunter unlikely to see any exploration and development. Metgasco has suspended its CSG activities in the Clarence Moreton Basin. Dart Energy has chosen to not pursue exploration in its Clarence Moreton acreage and is giving preference to its international acreage. (2014b, p. 2)

Dealing with economic and amenity effects through government payments to communities

Gas exploration and production can impose a range of economic and amenity effects on local communities. Some are positive, such as improved employment opportunities and increased economic activity in the region. Some are negative, including both the direct consequences of the gas activities themselves, such as visual effects, noise, dust and damage to infrastructure such as roads, and the effects resulting from population change. The latter could arise from an influx of employees of the gas company into the local community and could lead to higher land prices (leading to both benefits and costs within the community) and increased pressure on public infrastructure and services. These effects vary over time, depending on the stage of exploration or production.

A survey of the Chinchilla community on the edge of the Surat basin in Queensland revealed that amenity and lifestyle issues were the most important concern for local residents, well ahead of environmental issues (Williams and Walton 2014).

In some cases, it may be efficient for the gas company to pay for the adverse amenity effects and the costs it imposes on members of the local community. These situations include instances where the costs are easily quantifiable and can be clearly attributed to the gas company's activities. For example, there is a strong case for compensation for physical damage to a neighbouring property. However, as noted earlier, there are existing instruments for addressing such situations in legislation and/or common law.

In other cases the adverse economic and amenity effects are a symptom of a broader problem. The Commission (PC 2014a) previously found that large population shifts can affect local communities where there are existing market failures and inefficiencies in the provision of public goods, such as infrastructure. Such issues are best addressed through policy settings that directly target the problem. For example, the best way of addressing the pressures on local infrastructure is to fix any inefficiencies in the funding and provision of infrastructure. This would include ensuring that the relevant local councils are adequately resourced to perform their functions, including their responsibilities with respect to public infrastructure, or providing funding support from other levels of government (PC 2014a).

Return of royalties to local communities

One option that has been used in an effort to facilitate community acceptance of gas exploration and production involves governments committing some of their royalty receipts to the regions that host the gas industry. Queensland and Western Australia have introduced programs (Royalties for Regions) that earmark some of the royalties to regional projects (box 5.4). The Victorian Gas Market Taskforce (2013a) recommended the establishment of a similar program in Victoria.

Box 5.4 Royalties for Regions programs in Australia

Two states, Queensland and Western Australia, have established Royalties for Regions programs.

Queensland

Royalties for the Regions is a grants program that provides funds for regional local governments to deliver infrastructure projects. The projects are selected on the basis of several criteria, including: the project's alignment with the state's regional development policy (RegionsQ); response to economic and community needs; infrastructure improvement; community benefits; value for money; ongoing viability and demonstrated community support. For the period 2012-13 to 2015-16, \$495 million will be invested under the program.

Western Australia

Under the WA Royalties for Regions program, 25 per cent of the state's royalty receipts (around 5 per cent of the state's budget) have been earmarked for a broad range of regional projects, including infrastructure, housing, and various community programs. The grants are distributed through three specific purpose funds, administered by the Department of Regional Development and Lands. Between 2008-09 and 2014-15, around \$6.5 billion have been budgeted for the program, and around \$1.2 billion was disbursed in 2012-13.

Sources: DSDIP (2015); WA DRD (2014).

In New South Wales, the Gas Plan flags the development of a Community Benefits Fund to fund local projects in communities that host gas development. The NSW Government will contribute \$1 from its gas royalties for every \$2 provided to the Fund by the gas industry, capped at 10 per cent of the royalty take (NSW Government 2014c).

There are potential adverse implications for equity from policies that earmark some of the royalties for the benefit of a local community. Such approaches transfer the benefit from gas production from the general population to communities located in the vicinity of the gas industry's operations.

Earmarking royalties also raises issues on the spending side of the equation. Ideally, the decision on whether to undertake a particular public investment should be made independently of the question of how it will be funded (PC 2014b). Simply put, if a particular regional (or urban) project is supported by a robust cost-benefit analysis, investment should not be contingent on a specific and, ultimately, unrelated stream of revenue (in this case resource royalties).

There are further risks if regional investment priorities are influenced by the objective of building local community support for gas production and exploration. This approach could create an incentive for local communities to engage in unproductive rent-seeking behaviour.

Social licences to operate and community engagement initiatives

There is clear evidence of strong opposition to the gas industry, particularly CSG, in some sections of the community, both at a local and broader level (Taylor, Sandy and Raphael 2013). Some commentators have suggested that industry efforts to achieve greater acceptance have so far been inadequate (for example, Wood, Blowers and Chisholm 2014).

The reputation of the gas industry is in part a consequence of past behaviour by some companies. A NSW Legislative Council Committee (2012) reported statements from many stakeholders that CSG companies often exhibited ‘a sense of entitlement’ when pursuing access to the land, failed to communicate and provide adequate notice to the landholder about their operations and did not adequately supervise contractors. It also reported evidence that communities were not being adequately consulted.

The problems appeared to be more prevalent for smaller exploration companies that looked to discover the gas and sell the tenement to a larger CSG company and had no incentive to develop a long-term relationship with the landholders. The gas industry has acknowledged the poor practices by some companies and, while it is undertaking some efforts to rebuild its standing, it is struggling to change attitudes that have become entrenched.

The failure to achieve a ‘social licence to operate’ — an unwritten social contract between the gas company and the community — could have severe implications for gas companies. An Ernst and Young (2014) assessment of business risks faced by the global mining and metals industry in 2014-15 ranked the absence of a social licence to operate as the third highest risk, ahead of challenges in accessing and allocating capital, and of problems in accessing infrastructure.

The Minerals Council of Australia has described the potential consequences of operating without a social licence:

Communities may seek to block project developments; employees may choose to work for a company that is a better corporate citizen; and projects may be subject to ongoing legal challenge, even after regulatory permits have been obtained, potentially halting project development. (2005, p. 2)

In a recent example, the NSW Office of Coal Seam Gas responded to strong community protests and suspended the licence of gas explorer Metgasco for its drilling operations in Bentley, citing the lack of ‘genuine and effective community consultation’ as the reason (Roberts 2014b).

There are benefits in keeping social licence arrangements voluntary

Many of the gas producers, as well as some of the explorer companies undertake various initiatives aimed at facilitating community acceptance of their operations. Approaches range from provision of information and consultation with community members on the technical aspects of exploration and production, to the funding of services or infrastructure

within the community, such as contributions to hospitals, social housing and fire services (AGL Energy 2015a; QGC 2012; Santos 2011). APPEA (2014a) reported that, so far, the natural gas industry contributed around \$120 million to community projects and causes in Queensland. Such initiatives may be addressing some of the adverse economic and amenity effects of the gas industry on local communities.

Some members of the gas industry have also sponsored research into the effects their activities were creating on local and regional communities (box 5.5).

Box 5.5 Gas Industry Social and Environmental Alliance

The Gas Industry Social and Environmental Alliance (GISERA) was formed in July 2011 to undertake scientific research addressing the potential social, economic, and environmental ‘challenges and opportunities’ of the gas industry.

GISERA’s founding members are the CSIRO and Australia Pacific LNG, and they have since been joined by QGC. An initial investment of \$14 million was made, for a research period of five years.

GISERA’s research so far has focused on Queensland’s CSG and LNG developments. GISERA currently has 16 research projects under way covering its five main research areas:

- surface and groundwater
- agricultural land management
- terrestrial biodiversity
- marine environment
- social and economic effects of CSG developments on communities.

Source: GISERA (2014).

Where such initiatives are voluntary and informed, their benefits would be likely to outweigh the costs and governments have little role to play. There is a clear distinction between such measures and governments earmarking royalty payments to local communities discussed earlier.

However, there is no statutory requirement for gas companies to compensate communities for adverse economic and amenity effects of their activities. Notwithstanding this, there are some areas of interface between the mandatory legal and voluntary social licences. For example, in Queensland, major resource and petroleum project proponents are required to undertake a social impact assessment as part of the environmental impact statement process and to prepare a social impact management plan (DSDIP 2013).

One substantial risk from governments legislating a requirement to obtain a social licence is that this can distort the incentives of the parties. For local communities, the change in bargaining power can create incentives for rent-seeking and hold out. Imposing a legislated requirement of community engagement may also be inconsistent with the relational capacity, trust and goodwill that are typical pre-requisites for a social licence (Lacey 2013).

Another risk is that a mandatory social licence could interfere with existing property rights of landholders who are willing to host gas exploration or production activity on their property in return for adequate compensation. It is unclear for example, how the concept of a social licence to operate can be reconciled with the following clause in the Agreed Principles on Land Access signed by AGL Energy, Santos and NSW landholder groups:

The parties will uphold the Landholder's decision to allow access for drilling operations and do not support attempts by third party groups to interfere with any agreed operations. (Roberts 2014a, p. 2)

A further issue is that mandating a social licence for individual gas companies can make them responsible for addressing problems that were not of their making. For example, while the reputation of the industry may have suffered from the past practices of some companies, better performing companies would still be required to overcome the current community resistance to the industry overall.

Ultimately, some gas companies have exceeded their statutory obligations on landholder compensation, as well as in contributing to local communities. However, provision of financial contributions by the industry to gain community acceptance should not be a matter for additional regulation.

Social licences should complement, not replace sound regulation

While the achievement of a social licence to operate can be beneficial for the gas company and the affected local community, it may not be the best mechanism for resolving some land conflict issues.

First, clear regulatory standards are a more transparent mechanism for managing the environmental and social effects of gas exploration and production than any arrangements negotiated between gas companies and representatives of local communities.

Second, social licences do not deliver the same certainty of outcome as regulation, because of their inherently intangible nature (Lacey, Parsons and Moffat 2012) and the absence of a formal mechanism of enforcement (Gunningham, Kagan and Thornton 2004). This makes such arrangements less well suited than regulation for managing activities with significant environmental or social consequences.

Third, a social licence would not necessarily be an accurate reflection of the best interests across the whole jurisdiction. For example, production decisions affect the flow of royalty and taxation revenues to the broader community. Those outside of the region can also be affected if exploration or production generates adverse environmental effects that spread beyond the local area. It would be difficult to represent those broader interests in any social licence arrangement.

Even within local communities, there are those that derive benefits from gas production, and those for whom it leads to a decline in wellbeing. It may be challenging to achieve

consensus between those groups. A CSIRO survey of Queensland communities affected by CSG activities revealed significant differences between different groups of stakeholders on what issues they considered important (Williams and Walton 2014). The report by the NSW Chief Scientist and Engineer noted:

There is considerable social tension and animosity between some neighbours in some local communities where CSG operations are proceeding or proposed. On the one hand there are those who are concerned about potential negative impacts of CSG extraction and see those who want its introduction as ‘selling out’ to CSG companies. On the other hand, landowners and community members who are in favour of CSG often feel that the debate has been ‘hijacked’ by environmental activists who are ‘using’ the community for their own ends. (2014, p. 8)

These problems may be exacerbated by the difficulty for any community in assessing technical matters, where even experts may differ.

This underscores the importance of a robust evidence-based regulatory framework as the *primary* mechanism for managing the effects of gas exploration and production on the community.

In sum, achieving a social licence to operate should largely be a matter for the gas industry and local communities. This is not to say that the industry’s efforts to engage local communities have always been satisfactory in achieving the best outcomes for the community, or indeed, for the industry itself.

A code of practice for land access and community engagement

A well-designed uniform code of practice outlining the principles and elements of best practice community engagement for the gas industry, which is developed in consultation with, and endorsed by, key industry and landholder groups, may improve outcomes for the industry and the community, and address expectations of future interactions on both sides.

Currently, there is no consistency in the approaches adopted by gas companies to consult with and generally engage landholders and local communities. Some of the conduct is governed by legislation in the relevant jurisdiction.

Some gas companies also have internal company policies on landholder access negotiations and community consultation. The Agreed Principles on Land Access signed by AGL Energy and Santos with New South Wales landholders do not cover other gas companies, but may create pressure on those companies to follow suit, resulting in uncertainty for all parties. Ultimately, as noted above, conduct across the industry has varied, with the reputation of the industry suffering from the practices of some of its more poorly performing members.

Jurisdiction-specific codes of practice governing land access by resource companies (but not, specifically, gas companies) have been adopted in some states. For example, the Land Access Code developed by the Queensland Government (DEEDI 2010) sets out the

mandatory legislated requirements as well as voluntary best practice guidelines for maintaining good relations between landholders and the resources industry.⁹ In South Australia, a Code of Conduct for Mineral and Energy Explorers together with a Code of Practice for Community and Stakeholder Engagement have been developed by the resources and primary industry groups (SACOME nda; SACOME ndb).

A more uniform approach to landholder and community engagement that would be offered by an industry-wide code of practice can provide greater certainty and also serve as a useful source of information for gas companies, landholders and communities. The wind energy industry in Australia has faced similar issues with local community resistance to its operations. Its peak industry body — the Clean Energy Council — developed Community Engagement Guidelines for the Australian Wind Industry. That document provides an outline of the responsibilities and community expectations of the industry, for all stages of the wind project (CEC 2013).

As voluntary instruments, codes of practice do not have the same influence on the parties' behaviour as regulation. Nevertheless, they can have some regulatory force because of an implicit threat of 'hard regulation' should they fail to deliver on their objective of accommodating competing land uses in a relatively conflict-free manner (Sarker and Gotzmann 2009). Other potential benefits include flexibility and adaptability and an ability to harness the parties' knowledge to address the priority issues more directly (OECD 2009).

There may be a role for government in facilitating or coordinating the process and to provide information to assist the formulation of codes of practice. As discussed earlier, community concerns do not appear to be confined to any particular state or territory, so there may be merit in an inter-jurisdictional approach. The COAG Energy Council had previously released the National Harmonised Regulatory Framework for Natural Gas from Coal Seams and the Multiple Land Use Framework. The Council may also be well placed to coordinate the development of a code of practice on landholder and community engagement.

An independent body to facilitate stakeholder interaction

In addition to a code of practice, there may also be a case for a more active approach to facilitating the interaction between the gas industry and local communities on the ground. As discussed earlier, the Queensland Government has established an independent statutory body — the GasFields Commission — for this purpose.

Since commencing operations, the Commission has established two GasFields Community Leaders Councils, comprising a mix of stakeholders, to assist it in identifying co-existence issues. It meets regularly with those Councils to identify and discuss any issues that arise.

⁹ The Land Access Code itself is a regulatory instrument. However, the part of the Code that deals with establishing good relations between the parties is a best practice guideline.

The Commission has also released some guidance material for stakeholders, such as the guide for negotiating land access (discussed earlier).

It is too early to assess the effectiveness of the Commission in achieving its objectives. However, in principle, the model of an independent agency with powers to collect and disseminate information, advise government and directly engage stakeholders to resolve land use issues, may have merit.

The Chairman of the Parliamentary Committee that considered the GasFields Commission Bill stated that the public consultation process revealed strong support for the establishment of the body (SDIIC 2013). The Victorian Gas Market Taskforce argued:

In Queensland, which is now in a phase of large scale development, the establishment of a Gas Fields Commission has created significant improvements in the level of engagement between the Government, industry, landholders and communities. (2013a, p. 53)

The taskforce report recommended the establishment of a similar body in Victoria. There may be merit in thoroughly reviewing the operations of the Queensland GasFields Commission after a period to determine whether its benefits outweigh the costs, which could inform the case for introducing a similar agency in other states.

Concluding comments

The rapid growth of the gas industry in Australia has clearly presented significant challenges for governments in managing the effects of gas exploration and production on landholders, as well as local and broader communities. It is unsurprising that governments have struggled to develop a timely policy response that balances the sincere but conflicting concerns of landholders, industry, the local community and Australia as a whole. Governments need to address the legitimate concerns of the community about the broader effects of gas activities through evidence-based regulations and policies that are proportionate to the risks and are aligned with the costs and benefits of alternative uses of the land.

The gas industry also shares some responsibility for its poor standing in some communities, and while reaching unanimous support is unrealistic, there is a clear room for improvement in how it is perceived by the public. Further thought by explorers and producers on early engagement directly with communities, rather than simply on compensation for landholders, is needed.

Governments may be able to assist in facilitating interactions between the industry, landholders and local communities. However, the onus is on the gas industry to drive the development and adoption of principles for engaging the local communities within which it operates. Drawing on the discussion and conclusions presented in this chapter, the Commission's framework for managing the land use issues arising from gas exploration and production is presented below (table 5.2).

Table 5.2 A framework for managing the land use issues

<i>Issue</i>	<i>Who is affected?</i>	<i>Primary mechanism to address</i>	<i>Roles of the parties</i>	<i>Supporting mechanisms</i>
Direct costs of land access for gas activities	Landholders that host gas activities	Negotiated compensation from gas company to landholder that reflects the costs to the landholders from negotiating land access agreements and from the decline in the value of their properties	State governments to administer statutory regime for compensation	Facilitation of negotiations through agreement templates and guidelines developed by gas industry and landholder groups
	Owners of damaged neighbouring properties	Compensation from gas company to neighbours for incidental damage	Landholder and gas company to negotiate access terms	Publication of compensation benchmarks by state governments if costs are reasonable
Environmental and public health effects of gas activities	Local and broader community	Purpose-specific regulation	State governments to administer and enforce regulation Industry to comply with regulatory regime	Risk-reflective environmental insurance/assurance provided by gas companies for rehabilitation of adverse effects
Economic and amenity effects on local communities	Local communities	Land use planning instruments	State governments through the administration of land use planning regimes	Voluntary initiatives by gas industry to address adverse economic and amenity effects on local communities
		Arrangements for provision and funding of public infrastructure	Commonwealth, state and local governments to address public infrastructure issues	
Social effects of gas activities	Local communities	Development of voluntary code of practice for community engagement for the gas industry	Industry and landholder groups to develop the code Australian Government to coordinate	Potential merit in an independent agency to manage industry and community interactions on the ground

6 Policy issues in markets for transmission pipeline capacity

Key points

- Further development of the eastern Australian gas market would require investment in gas transmission pipelines. Timely investments in gas transmission pipelines can help to relieve physical gas supply constraints and put downward pressure on prices.
- Previous gas market reviews and gas market participants have argued that there are potential barriers to improved outcomes in transmission pipeline capacity markets under the contract carriage model, including that:
 - a lack of transparent information on the availability of pipeline capacity may inhibit capacity trading in secondary pipeline capacity markets
 - pipeline users with firm capacity rights may have an ability and incentive to ‘hoard’ capacity to limit competition downstream.
- Previous gas market reviews and gas market participants have also argued that regulatory arrangements under the National Gas Law and the market carriage model that applies in parts of Victoria may be limiting investment in pipeline capacity.
- The COAG Energy Council is progressing reforms to increase information transparency and facilitate greater trading in secondary pipeline capacity markets.
 - Transparency should not be forced simply for its own sake given the potential costs from requiring market participants to make information available. Nonetheless, increased transparency can help to reduce transaction costs and facilitate secondary pipeline capacity trading, increasing the opportunities for pipeline capacity to be allocated to its highest value uses.
- Gas market stakeholders have proposed changes to the way capacity is allocated under the contract carriage model. There have been proposals to extend the open access principles that apply under the market carriage model, and calls for the introduction of mandatory pipeline capacity trading provisions that apply in other countries.
 - In the Commission’s view extending elements of the market carriage model could put at risk the investments needed to efficiently respond to current and future market developments. There would also be significant risks from adopting mandatory pipeline capacity trading provisions that apply in other countries, especially if such provisions involve the over-riding of private property rights.

Transmission pipelines connect gas production and processing facilities with domestic and export markets. Transmission pipeline capacity markets include both primary pipeline capacity markets (the initial allocation of capacity by pipeline owners) and secondary pipeline capacity markets (capacity trading between different users). Outcomes in transmission pipeline capacity markets influence investment and the level of competition throughout the gas supply chain. Transmission pipeline capacity markets will have a significant bearing on how efficiently gas markets respond to market developments, including the substantial investments in liquefied natural gas (LNG) export facilities in the eastern Australian gas market.

The regulatory and market arrangements applying to transmission pipelines influence how pipeline capacity is allocated, and the incentives for pipeline investments (including new or expanded pipelines). These arrangements should not unnecessarily create barriers to efficient outcomes in transmission pipeline capacity markets.

6.1 Pipeline capacity allocation and investment

Allocation of rights to transmission pipeline capacity

Well-functioning markets for pipeline capacity can help to ensure that capacity is allocated to its highest value uses. Important characteristics of well-functioning transmission pipeline capacity markets include: well-defined tradeable property rights over the use of capacity; competition between companies for access to capacity; sufficient information on the availability of capacity; and sufficiently low transaction costs (chapter 2). Where these characteristics are absent or distorted, markets may fail to allocate capacity to its highest value uses.

There are two broad approaches to allocating pipeline capacity in Australia

The nature of property rights and the importance and availability of information differ across the two broad approaches (or ‘models’) for allocating pipeline capacity in Australia — the ‘market carriage’ model and the ‘contract carriage’ model. As noted below, gas market stakeholders have differing views on the relative merits of these models (table 6.1).

The market carriage model is used to allocate pipeline capacity rights in the Victorian Declared Transmission System (DTS).¹ Under this model, the pipeline owner (APA Group) makes its system available to the Australian Energy Market Operator (AEMO) who manages pipeline capacity through a pool approach (AEMC 2015a). Capacity is bundled with gas purchased in the Declared Wholesale Gas Market (DWGM). AEMO clears the DWGM on an intra-day basis according to a merit order based on market participants’ bids

¹ The DTS consists of an extensive pipeline network, with four major transmission pipelines (AEMO 2012b).

to purchase gas. Users do not reserve physical capacity (meaning there are no long-term capacity rights), instead they obtain a financially firm right (AEMC 2015a). With no long-term capacity rights there is also no scope (or need) to trade capacity in secondary pipeline capacity markets. The Australian Energy Regulator (AER) regulates pipeline tariffs on the basis of approved infrastructure costs (see below).

The contract carriage model is used to allocate pipeline capacity rights outside the Victorian DTS. Under this model, allocation of capacity occurs independently from wholesale gas markets through long-term contracts between the pipeline owner and user ('contract holder'). These contracts, which outline a range of terms and conditions, typically confer a property right to the contract holder for a given amount of pipeline capacity (usually in the form of a maximum daily quantity) (AEMC 2015a). The extent of these property rights is generally limited to when the capacity is used — the pipeline owner can reallocate unused capacity to other users by selling 'as available' capacity rights. Contract holders can sell unused capacity in secondary pipeline capacity markets either through a 'bare transfer' (temporary transfer) or by 'novation' (permanent transfer that involves a new contract) (SCER 2013b).

Investment in transmission pipeline capacity

The importance of efficient investments in transmission pipelines

Future investment in gas transmission pipelines will depend on a number of factors, including: how much demand there is for gas and where this gas is needed; the relative costs of producing gas at different fields and basins; future development of trading hubs such as the Wallumbilla Gas Supply Hub; and future LNG prices.

It is not possible to predict how these factors will evolve. Recent experience has illustrated that key factors affecting LNG prices (such as oil prices) can be volatile. With this in mind, the Commission has used its model of the eastern Australian gas market to estimate the broad geographical patterns of future pipeline investment under three LNG price scenarios over a twenty year modelling period — 'low LNG price', 'central LNG price' and 'high LNG price' scenarios (box 6.1). To illustrate the relationship between LNG prices and future investment, the Commission has reported investment outcomes for the low LNG price and high LNG price scenarios. The full range of results is included in appendix C (available online).

Investments in gas transmission pipelines are considered efficient if they are made when their total expected benefits exceed their full economic costs (chapter 2). Efficient investments ensure that capacity increases are directed toward areas of greatest value, and are made in a timely manner. Timely investments can help to relieve physical gas supply constraints, and provide opportunities for producers to access gas markets, putting downward pressure on prices.

Box 6.1 Investment outcomes in the Commission’s modelling of the eastern Australian gas market

The Commission’s model was used to estimate the pipeline investment that would occur in a competitive market environment, and in so doing illustrates the drivers of efficient investment. Details of the Commission’s modelling approach and the data used are included in appendix B.

Modelled investment in transmission pipelines is substantially higher under a high LNG price scenario. Model results indicate that under a high LNG price scenario, an efficient response to the growth in Queensland LNG exports will require existing pipelines to be expanded. Investment will be needed throughout the eastern Australian gas market. However the majority of modelled investment occurs in pipelines serving LNG export facilities in Queensland. In particular, pipeline capacity between the Surat-Bowen basins and Gladstone increases by about 1400 petajoules per year (PJ per year)² over the 20 year model period. There is a smaller capacity increase in the South West Queensland Pipeline (Cooper basin to Surat-Bowen basins) pipeline (around 265 PJ per year).

Under the low LNG price scenario most modelled pipeline investment occurs in pipelines serving domestic markets, with capacity in the South West Pipeline (Otway to Melbourne) and the Eastern Gas Pipeline (Gippsland to Sydney) increasing by about 110 PJ per year and 20 PJ per year respectively.

Delays to transmission pipeline investments can arise due to the time taken to complete economic and environmental regulatory approval processes, and through the potential for economic regulation to raise investment hurdles by reducing the expected returns from a project or increasing project risks (see below). All large capital investments involve a lag between when a final investment decision is made and when the investment becomes operational. However, delays to gas transmission pipeline investments beyond this lag impose costs on gas market participants and the broader community. In particular, delays to investment can lead to transmission constraints that increase prices in affected areas. They can also lead to less investment in new sources of gas supply, requiring producers to draw on more expensive reserves from existing fields, further adding to price pressures.

The Commission has used its model of the eastern Australian gas market to illustrate the mechanisms by which delayed pipeline investments (both the building of new pipelines and expansions of existing pipelines) could impose such costs. Effects are estimated by comparing model outcomes under a ‘what if’ scenario. Under this scenario, modelled future investments in transmission pipelines serving the domestic market are delayed by five years. By contrast, in the baseline scenario delays due to regulatory arrangements do not occur. Delays do not apply to pipelines directly serving the LNG export facilities in Gladstone, as these pipelines are subject to binding no coverage decisions and are not subject to regulation or the threat of regulation.³ Nonetheless, supply to export markets can be affected by

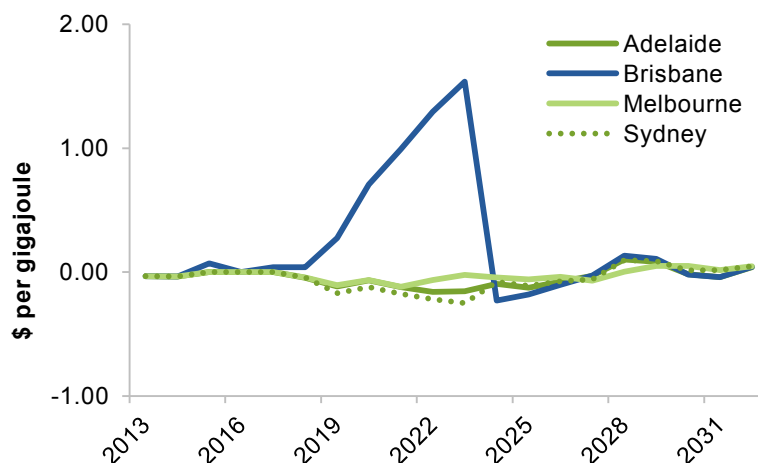
² Pipeline capacities are generally reported in terajoules per day. The Commission has reported pipeline capacity increases in petajoules per year to maintain consistency with the rest of the report.

³ The Australia Pacific LNG, Queensland Curtis LNG and Gladstone LNG pipelines have received no coverage determinations (box 6.2).

constraints in pipelines that interconnect with the pipelines directly serving LNG export facilities.

Model results indicate that if investments are delayed, supply is constrained and gas prices increase in areas directly affected by transmission constraints. In particular, gas users in Brisbane are subject to transmission constraints, leading to an increase in prices that abates after new transmission capacity becomes available (figure 6.1). For the most part, prices do not increase in other demand centres because in the modelled future scenario these areas are not subject to pipeline constraints. Delays to pipeline investments also increase the volatility of wholesale gas prices relative to the baseline under all three LNG price scenarios.

Figure 6.1 Changes in consumer gas prices under central LNG price scenario due to transmission pipeline investment delays^a
Results from the Commission's modelling of the eastern Australian gas market



^a The figure displays the change in wholesale gas prices relative to a baseline scenario without investment delays. Transmission investment delays of five years have been modelled for pipelines serving the eastern Australian gas market.

Pipeline investments are inherently risky for investors

Investments in gas transmission pipelines involve large upfront costs that are mostly sunk once the investment is made. The sunk and relationship-specific nature of transmission pipelines may give rise to 'hold-up' risks. On the one hand, there is a risk for users that a pipeline owner will raise its prices to extract some of the value of a sunk investment that depends on access to the pipeline. On the other hand, in the absence of contractual arrangements there is a risk for pipeline owners that a user will refuse to pay the price agreed to prior to the owner making its sunk investment. Hold-up risks are considered to be greater where there are highly relationship-specific assets (such as a point-to-point pipeline) and few buyers and sellers (a situation referred to in the economics literature as a 'small-numbers bargaining problem') (Hubbard and Weiner 1991; Williamson 1975).

The mechanisms used by investors to mitigate and manage these risks play an important role in facilitating pipeline investments.

Long-term contracts that establish and enforce property rights over capacity help to mitigate the risks involved in making pipeline investments, and more generally enable risks to be assigned to the party best placed to manage them. As noted by the International Energy Agency:

Long-term contracts can be seen as a measure of risk mitigation for market players. They often ensure a defined amount of gas to be traded between producer/seller and buyer during a time span which can reach up to 20 or 25 years. ... It is important to keep in mind that in an early stage of development, no gas market has started out with anything other than long-term contracts. (2012, p. 65)

Vertical integration is another strategy to address the risks from making pipeline investments. However, vertical integration can heighten incentives for pipeline owners to deny requests from third parties for access to unused capacity (PC 2013c), and there are provisions under the National Gas Law (NGL) that prevent owners of regulated (or ‘covered’) pipelines from carrying on a related business (producing, purchasing or selling natural or processable gas).

Importantly, to motivate transmission pipeline investments, the expected returns need to compensate investors for the risks from investment (and other costs). This suggests that returns that cover more than just the variable cost of supply may not necessarily be a reflection of the exercise of market power. Rather, they may simply be a normal return to scarce pipeline capacity (Sidak and Teece 2009). The prospect of high returns provides an important signal for bringing on new pipeline investment, including where increased capacity would provide the greatest payoffs.

There are different arrangements for investing in pipeline capacity

The arrangements for investing in pipeline capacity differ between the market and contract carriage models. There are also different arrangements for pipelines that are regulated under the NGL. The arrangements for transmission pipeline regulation under the NGL are outlined in box 6.2.

The pipeline system operating under the market carriage model (the Victorian DTS) is subject to full regulation under the NGL. All users of the DTS pay for approved investment expenditure through regulated access charges.

Box 6.2 **Transmission pipeline regulation under the NGL**

The NGL and National Gas Rules (NGR) set out the basis for regulation of third party access to gas pipelines. The NGL only applies access regulation to pipelines with a ‘coverage’ determination. The National Competition Council (NCC) considers applications for coverage and provides recommendations to Ministers responsible for making coverage determinations. To become covered, a pipeline must meet various ‘coverage criteria’ set out in the NGL.

The NCC decides whether a covered pipeline is subject to full regulation or light regulation.

- Full regulation requires the service provider to submit an access arrangement to the regulator (the AER in the eastern and northern gas markets, and the Economic Regulation Authority in the western gas market) for approval as part of an ‘access arrangement review’. Approved investment expenditure and predictions about capital expenditure requirements are included in a capital asset base for determining regulated access charges. The DTS, Central Ranges, Roma to Brisbane, Dampier to Bunbury, Goldfields, and Amadeus pipelines are currently subject to full regulation.
- Light regulation imposes a negotiate/arbitrate model for access, with arbitration by the regulator in the event of a dispute. Covered pipelines are also subject to other regulatory requirements under the NGL (for example in relation to ring fencing of certain activities and the provision of information). The Carpentaria, Central West, Kalgoorlie to Kambalda and parts of the Moomba to Sydney pipelines are currently subject to light regulation.

Covered pipelines may have their coverage revoked if they no longer meet the coverage criteria (for example, if it is no longer considered that access to the pipeline would promote competition). A number of pipelines have had their coverage revoked in recent years, including the Dawson Valley Pipeline (in 2014), the Moomba to Adelaide Pipeline System (2007), and the Tubridgi and Griffin Pipelines (2006). A pipeline developer can also apply for a ‘no coverage’ determination that provides a 15-year exemption from coverage under the NGL for greenfield pipelines under specified circumstances. The Australia Pacific LNG, Queensland Curtis LNG and Gladstone LNG pipelines have received no-coverage determinations.

Sources: NCC (2013); PC (2013c).

Some reviews have noted that the lack of long-term firm capacity rights under the market carriage model may discourage potential users from underwriting capacity investments (Department of Industry 2013; K Lowe Consulting 2013). While users cannot contract for long-term firm capacity rights, pipeline users can buy authorised maximum daily quantity (AMDQ) and AMDQ credit certificates (collectively referred to as AMDQ), which provide higher priority access to capacity in certain circumstances than users with no AMDQ.⁴

Under the contract carriage model, investments are underpinned by long-term contracts between pipeline owners and contract holders. These contracts — which the Commission has heard from some project participants can take months to negotiate — typically provide contract holders with long-term firm capacity rights under ‘take or pay’ conditions, which charge for pipeline capacity rights, regardless of whether the capacity is used. There are also

⁴ AMDQ provides higher priority access if there is a tie in injection bids, or if there is a constraint in the DTS that requires curtailment of some users. It also provides a hedge against congestion uplift charges (payable by market participants that cause congestion in certain circumstances) (AEMO 2014a).

variable throughput charges that only apply when capacity is used. A number of stakeholders consider that long-term contracts play an important role in mitigating and managing the risks from investing in transmission pipelines (AGL Energy 2014a; Alinta Energy 2014; ESAA 2014b; Queensland Government 2014b).

For contract carriage pipelines that are subject to full regulation under the NGL, the regulator has a role in determining the returns made on pipeline investments, and in doing so considers capital expenditure requirements (box 6.2). Decisions by the regulator can therefore affect the nature and timing of investments made in regulated pipelines. While the National Gas Rules (NGR) provide for ‘speculative investments’ to be made within regulatory periods, this has rarely occurred in practice (Victorian Gas Market Taskforce 2013b).⁵ The regulator does not have any oversight of investments made in pipelines that are not regulated (although the threat of regulation could affect investment decisions).

6.2 Potential barriers to efficiency in transmission pipeline capacity markets

Previous gas market reviews and gas market participants have argued that there are potential barriers to improved outcomes in transmission pipeline capacity markets under both the contract carriage and market carriage models. The issues raised concern the mechanisms used to allocate rights to pipeline capacity under the contract carriage model. There are also concerns about the effects of economic regulation under the NGL, and arrangements under the market carriage model on incentives to make efficient investments in pipeline infrastructure.

Potential barriers to efficient capacity allocation under the contract carriage model

Lack of transparent information and transaction costs

Previous gas market reviews have highlighted a lack of transparent information on the identity of pipeline capacity contract holders, pipeline usage rates, and the availability and price of capacity in secondary pipeline capacity markets (Department of Industry 2013; Grattan Institute 2013; Victorian Gas Market Taskforce 2013a). A lack of transparent information on the availability of pipeline capacity, and the higher transaction costs that this entails, are potential barriers to trading capacity in secondary pipeline capacity markets.

⁵ If an investment does not conform to capital expenditure criteria outlined in the NGR, it can be added to the speculative capital expenditure account. If a ‘speculative investment’ later complies with the capital expenditure criteria, it can be added to the capital asset base.

As noted in chapter 2, good information and low transaction costs are important features of a well-functioning market. A lack of transparent information could inhibit the entry of new suppliers into retail markets, and could limit the efficiency and liquidity of physical wholesale supply hubs, which depend on flexible and short-term access to pipeline capacity (Department of Industry 2013; ESAA 2014b). EnergyAustralia (2013b) has argued that transparency in transmission pipeline capacity markets (along with a diminishing role for long-term contracts) is the key to achieving liquidity and transparency in gas markets more broadly.

Transaction costs are not the only factors that potentially influence outcomes in secondary pipeline capacity markets. The extent of trading in secondary pipeline capacity markets also depends on whether there are buyers and sellers that place different valuations on pipeline capacity at a given point in time, and whether capacity is available in a form required by buyers (for example, some buyers may require firm capacity rights). There may be few trades in secondary pipeline capacity markets due to the small size of Australia's gas markets (EnergyAustralia 2013b), or due to a lack of common delivery points (AGL Energy 2014b). For contract holders, legitimate commercial considerations may mean that the costs of executing a trade outweigh the benefits (ERM Power 2014b). For example, selling capacity can be costly, because it involves relinquishing a 'real option' to use capacity at a later time, which can be used as a risk management tool in an environment of market uncertainty.⁶

Competitive access to pipeline capacity and incentives to hoard capacity

Reviews undertaken for the Australian Energy Market Commission (AEMC) and AEMO stated that pipeline users with firm capacity rights may have an ability and incentive to 'hoard' their capacity in order to limit competition in the downstream markets in which they operate (K Lowe Consulting 2013; The Brattle Group 2013). This can lead to 'contractual congestion', a situation where market participants are unable to gain access to unused pipeline capacity because all capacity is contracted (SCER 2013b).

As noted in chapter 2, competition (and the threat of competition) is an important feature of a well-functioning market. If competitive access to transmission pipeline capacity is restricted, higher gas prices may be imposed on domestic users. For example, a gas retailer with contracted but unused capacity may reject a request from a potential competitor to use its unused capacity, enabling it to charge higher prices to end users of gas. Further, if competition is impeded in downstream markets (such as retail markets) there may be reduced incentives to develop new sources of supply. Concerns with the effects of capacity hoarding in the European Union have led to the introduction of mandatory pipeline capacity trading provisions there.

⁶ Real options to use spare capacity at a later time are valuable because they provide the contract holder an opportunity to expand output without the need to enter secondary pipeline capacity markets (and face any associated price risks) if demand increases.

Contract holders may have strong incentives to sell, rather than hoard, unused capacity. In a report for the AEMC, K Lowe Consulting argued:

... while a [contract holder] may appear to have little incentive to sell spare capacity to a downstream competitor, the fact that a pipeline owner can sell that same capacity on an ‘as available’ basis, should encourage the [contract holder] to compete to supply the service and recover some of its fixed transportation costs. (2013, p. 121)

However, even if contract holders have an incentive to sell capacity, there are a number of reasons why capacity trades may not occur, including transaction costs. Hence, regardless of whether capacity hoarding occurs, allocating primary pipeline capacity through long-term contracts may reduce the flexibility with which capacity can be efficiently reallocated under the contract carriage model if there are barriers to trading capacity in secondary pipeline capacity markets.

Potential barriers to efficient investment

Regulatory arrangements under the National Gas Law

There are arguments that some of the regulatory arrangements under the NGL increase the risks from investing in spare pipeline capacity, and that as a result only contractually committed capacity is built (APA Group 2013a; APIA 2013). There are also concerns that regulated rates of return do not fully compensate for the costs incurred from investment, including for some of the risks associated with introducing new services (APA Group 2013a). There are currently six pipelines (the Victorian DTS and five pipelines operating under the contract carriage model) subject to full regulation under the NGL (box 6.2).

Some pipeline owners consider that the following regulatory arrangements under the NGL can increase the risks from investing in spare capacity.

First, the regulator can determine that unused pipeline capacity is ‘redundant’ and, as a result, remove it from the capital asset base used to determine regulated access prices (APA Group 2014).⁷ A decline in upstream production volumes or demand that leads to unused pipeline capacity could result in that capacity being declared redundant by the regulator, decreasing the size of the capital asset base. A smaller capital asset base would in turn result in lower regulated access prices.⁸

Second, some pipeline owners also consider there is a risk that, when determining regulated prices for access to expanded pipeline capacity, the regulator would consider the

⁷ NGR 85(1) allows an access arrangement to include ‘a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base’.

⁸ In a price determination for the Wilton to Wollongong transmission pipeline, the NSW Independent Pricing and Regulatory Tribunal (IPART 2005) declared that part of the pipeline’s capacity was redundant due to decreased utilisation, and removed it from the regulated asset base.

average costs associated with the total pipeline (including the original depreciated capital base), rather than just the costs associated with the expansion (APA Group 2013a; APIA 2013). Taking into account the original depreciated capital base would lower the average cost of pipeline services, resulting in lower regulated prices for access to expanded pipeline capacity than otherwise. For current users of a pipeline that pay prices determined under a privately negotiated contract, this creates a risk that spare capacity would be available to competitors at a lower price. Users may seek to shift this risk to the pipeline owner through a ‘most favoured nation’ clause, which allows incumbent users to access capacity on terms and conditions that are at least as favourable as those available to other users.

It is difficult to estimate what effects the above regulatory arrangements have had on investment. There are a number of reasons for this, including the inability to observe what investment would have occurred under alternative regulatory arrangements, and the difficulty of isolating the influence of regulation from other factors that may affect investment (such as risk preferences and the cost of accessing finance).⁹ The Australian Pipeline Industry Association (APIA) has stated:

It is very difficult to measure the direct effect the [NGL] has had on investment, and it is not possible to observe what investment might have occurred. We can only observe what has occurred. (2013, p. 12)

However, it is clear that access regulation can affect investment incentives. If pipeline owners are uncertain about how regulation would be applied (as discussed above) and if there are risks associated with the arrangements for determining regulated prices to expansions, the risks from investing in pipeline infrastructure could be compounded. These risks could increase investors’ hurdle rate of return for making investments in spare capacity beyond the expected return, inhibiting investment. Also, if regulated rates of return are not expected to fully compensate investors for the risks incurred, investments may not proceed. Given that regulators are unable to set optimal access prices (prices that would maximise overall economic efficiency) with precision, there is also scope for regulatory error in the setting of access terms and conditions (PC 2013c).

Some stakeholders have argued that access regulation results in pipeline capacity expansions being made incrementally to avoid risks associated with regulation. APIA considered that ‘in many recent pipeline expansions, a project to further expand the pipeline commences shortly after, or even prior to, completion of the initial expansion project’ (2013, p. 13). The commissioning of the Stage 4 and Stage 5A expansion projects for the Dampier to Bunbury pipeline both occurred after the Board had decided to proceed with another separate expansion project (DUET Group 2007, 2009). Given the likely economies of scale from building larger pipelines, in the absence of regulatory distortions,

⁹ It would also be difficult to estimate the effects of regulatory arrangements on pipelines that are currently unregulated, but could potentially be subject to regulation in the future. While recent coverage revocations (box 6.1) have decreased the likelihood of certain pipelines being regulated under the NGL, for some pipelines there is still likely to be a threat of regulation.

investment could entail some spare capacity where readily foreseeable demand exceeds currently contractible demand.

The market carriage model

Some concerns have been raised regarding investment incentives under the market carriage model. It is argued that the absence of long-term firm capacity rights under the model provides pipeline users with little incentive to underwrite capacity investments (Department of Industry 2013; K Lowe Consulting 2013). K Lowe Consulting noted:

... it would appear from our review that a number of factors have contributed to the investment and export issues observed in Victoria. The root cause of most of the issues can, however, be traced back to the fact that market participants are unable to obtain exclusive firm capacity rights on the pipeline system under the existing model. (2013, p. xvi)

It is also argued that the regulatory process for approving investment under the market carriage model leads to delayed investment (APA Group 2014). In particular, investment opportunities that arise during a regulatory period may be deferred until the next access arrangement review because of the risk that the investment will not be approved as part of the subsequent access arrangement.

As noted above, estimating the effects of regulation on investment is difficult. However, there is scope for the arrangements under the market carriage model to inhibit investment. Despite AMDQ providing higher priority access in certain circumstances (see above), there is an absence of long-term property rights over the use of capacity. A pipeline user who underwrote an expansion could be outbid by other users for the right to use the capacity associated with its investment. This provides the investor with no guarantee that it would receive access to its investment and would increase the risks from underwriting capacity.

K Lowe Consulting (2013) argued that the investment procedures under the market carriage model led to delays in an expansion of the South West Pipeline. In 2008, the Australian Competition and Consumer Commission (ACCC) declined a proposed expansion of the South West Pipeline in the proponent's capital asset base — and consequent price rise — in a 2008–2012 DTS access arrangement review.¹⁰ The ACCC said it was not convinced that the cost–benefit analysis provided by APA Group demonstrated that the expansion was appropriate (ACCC 2008). While the expansion was originally proposed to occur in 2012, a subsequent increase in the capacity of the Iona Gas Plant led to a proposal from a market participant to bring forward the expansion to 2009 (APA Group, pers. comm., 27 February, 2015). An expansion of the pipeline was approved in the subsequent access arrangement, and was completed at the end of 2014. This suggests the expansion potentially could have occurred five years earlier if it had been approved.

¹⁰ The ACCC was responsible for regulating covered transmission pipelines outside Western Australia prior to the NGL and NGR taking effect on 1 July 2008 (AER 2013a).

6.3 Assessing the case for policy change

Previous gas market reviews and gas market stakeholders have proposed policy changes to address some of the issues highlighted above. The Commission has considered below proposals for policy change aimed at improving capacity allocation under the contract carriage model. The AEMC is conducting two concurrent reviews that will provide an opportunity to consider whether there is a need to reform elements of the NGL and market carriage model to improve investment incentives.¹¹

Gas market policy reform should aim to improve overall economic efficiency across the gas supply chain. As noted in chapter 2, overall economic efficiency is comprised of several elements (allocative, productive and dynamic efficiency). There are potential tradeoffs between the different elements of efficiency for different gas market stakeholders. Proposals for policy change should therefore be assessed within an economic framework that accounts for these potential tradeoffs.

The market carriage and contract carriage models

Much of the debate concerning how transmission pipeline capacity should be allocated has centred on stakeholders' views of the relative merits of the market carriage and contract carriage models (table 6.1).

The market carriage model is considered by some to promote entry into downstream markets, and to more efficiently allocate capacity (Australian Paper 2014; K Lowe Consulting 2013). K Lowe Consulting (2013) said this was because the model facilitated access by highest value users, and because the lack of contractual rights over capacity avoided any problems associated with the existence and exercise of market power. Some previous gas market reviews have highlighted concerns that the market carriage model does not promote efficient investment (see above).

The contract carriage model is considered by some gas market stakeholders to promote more efficient investment by allowing parties to manage the risks from investment (Alinta Energy 2014; ESAA 2014b; Queensland Government 2014b). However, as highlighted above, there are concerns that pipeline capacity may not be allocated efficiently at a given point in time under the contract carriage model.

¹¹ The AEMC has been tasked by the COAG Energy Council to review and consider reforms to the design, function and roles of facilitated gas markets and gas transportation arrangements (COAG Energy Council 2014), and by the Victorian Government to review the Victorian DWGM (AEMC 2015b).

Table 6.1 Stakeholder views on the relative advantages of market carriage and contract carriage models

<i>Model</i>	<i>Stakeholder views on relative advantages</i>
Market carriage	<ul style="list-style-type: none"> • Capacity allocation is more efficient • No scope for capacity hoarding • No need for secondary pipeline capacity markets • Promotes efficient outcomes in upstream and downstream markets^a • Suited to meshed pipeline networks
Contract carriage	<ul style="list-style-type: none"> • More efficient and timely investments • Better enables the management and allocation of investment risks • Maintains private property rights over capacity • Scope for a broader range of pipeline service offerings • Lower regulatory and administrative costs

^a If regulated prices are mistakenly set either above or below the level that promotes overall economic efficiency, there could be an inefficient amount of investment in upstream or downstream markets.

Sources: APA Group (2014); Department of Industry (2013); K Lowe Consulting (2013).

The advantages of each model will be more or less important in different circumstances. Some gas market stakeholders consider that the market carriage model, which does not require firm capacity rights to be defined, could provide advantages in ‘meshed’ pipeline networks (which have multiple injection and withdrawal points) where it is difficult to cost-effectively define capacity rights.¹² There can be difficulties in allocating and trading capacity on meshed networks because the capacity in one part of the network may depend on what is being injected and withdrawn in another part of the network. The development of meshed pipeline networks could be promoted if firm capacity rights do not need to be defined. In point-to-point pipeline networks and where there is considerable scope for future pipeline investments, the contract carriage model may be the most suitable model.

However, the relevant policy decision should not be considered a choice of one model over another. Instead, the strengths and weaknesses of elements of each model should be considered in the context of the expected future needs of Australia’s gas markets — if the sector grows and becomes more liquid, or if other changes occur, the relative merits of some of these elements may change. In commenting on the tradeoffs between the market carriage and contract carriage models, Origin Energy noted:

... a review of the carriage models may be appropriate to support the continued development of the gas market. This review should not presuppose one model is better than the other and therefore that the objective of the review is a transition to the perceived better model. Instead it should focus on identifying the strengths and weaknesses of the two models and whether

¹² However, these sorts of pipeline networks can evidently still operate effectively in circumstances where capacity is allocated under long-term contracts. The Henry Hub in the United States, where transmission pipeline capacity is generally allocated under long-term contracts, consists of a network of more than a dozen major natural gas pipelines, as well as multiple delivery and receipt points (FERC 2012).

firstly, there is scope for consistency between the models and secondly, an evolutionary process to a single model is appropriate. An assessment of costs and benefits should also support any case for change. (2014b, p. 6)

Capacity allocation under the contract carriage model

Gas market stakeholders have proposed changes to the way capacity is allocated under the contract carriage model. For example, there have been proposals to extend the open access principles that apply under the market carriage model to elsewhere in the eastern Australian gas market (Australian Paper 2014; Manufacturing Australia 2014a). There have also been calls for the introduction of mandatory pipeline capacity trading provisions that apply in other countries. QGC (2014) encouraged policymakers to consider the adoption of mandatory pipeline capacity trading provisions, such as those that apply in the European Union, which enable regulators to reallocate unused capacity. GDF Suez (2014) has proposed a hybrid pipeline capacity trading model based on the Henry Hub in the United States.

On the one hand, adopting open access principles or introducing mandatory pipeline capacity trading provisions could in some cases facilitate the reallocation of pipeline capacity to higher value uses. Making access to secondary pipeline capacity easier for market participants could encourage more efficient responses to demand and supply imbalances in different parts of the eastern Australian gas market. These policy changes could also assist the development of wholesale spot markets.

On the other hand, adopting open access principles or introducing mandatory pipeline capacity trading provisions would entail significant risks.

Adopting open access principles could put at risk the investments in gas transmission pipelines that would be needed to efficiently respond to further development in the eastern Australian gas market. Some previous gas market reviews have highlighted concerns that the market carriage model may not create sufficient incentives for investment. As highlighted above, if investments are delayed, supply is constrained and gas prices increase in areas directly affected by transmission constraints. Delays to pipeline investments can also increase the volatility of wholesale gas prices. Adopting open access principles would also require the removal of obligations in long-term contracts. Removing such obligations could impose substantial costs on market participants throughout the supply chain.¹³

There would also be significant risks from adopting mandatory pipeline capacity trading provisions that apply in other countries. Some gas market participants have highlighted that mandatory pipeline capacity trading provisions would compromise or impinge on the

¹³ The elimination of obligations in long-term pipeline contracts in the United States in the 1980s resulted in transition costs estimated at over \$US10 billion by 1995 (US Department of Energy 1995). The process required further reforms to allow pipeline companies to pass on 75 per cent of these costs to producers, distribution companies and large consumers (EnergyAustralia 2013a).

property rights of contract holders (AGL Energy 2014a; ESAA 2014b). If mandatory pipeline capacity provisions involve the over-riding of private property rights, there could be substantial costs, including by diminishing incentives for future investment. Importantly, the effect of such provisions in other countries is unlikely to provide clear policy guidance in Australia. Australia's gas markets fundamentally differ from gas markets in the United States and Europe, which are more developed, more liquid and have many more buyers and sellers.

However, it is unclear whether adopting open access principles and introducing mandatory pipeline capacity trading provisions would deliver significant benefits or would be the best policy response. Importantly, an inability to access capacity does not necessarily indicate that capacity is being inefficiently hoarded — as highlighted above, there are a number of reasons why capacity trades may not occur. Hence, what may appear to be inefficient hoarding of capacity may instead be commercial behaviour that is consistent with outcomes from effectively competitive markets.

Information transparency and transaction costs under the contract carriage model

Pipeline owners and contract holders may have strong incentives to sell unused capacity where transaction and other costs are not prohibitive. The Energy Supply Association of Australia argued:

... where regulatory intervention is to be considered, a light-handed and incremental approach that has appropriate regard for existing contracts is likely to be the most appropriate response. Efforts to improve information provision and potentially reduce transaction costs appear to be a good starting place in this regard. (2014b, p. 7)

Pipeline owners and governments are both progressing measures aimed at facilitating greater secondary pipeline capacity trading under the contract carriage model. APA Group and Jemena have begun developing online capacity trading platforms for some pipelines. APA Group's trading platform is operating for the Roma to Brisbane, South West Queensland, Carpentaria and Moomba to Sydney pipelines. Some capacity trades have taken place on the platform. The COAG Energy Council, in consultation with market participants, is increasing the information available on the National Gas Market Bulletin Board and developing standardised secondary pipeline capacity market contracts.¹⁴ The relevant Regulation Impact Statement described these reforms as a low-cost and light-handed regulatory approach (SCER 2013b). The COAG Energy Council's reforms are scheduled to be completed in 2016 (COAG Energy Council 2015).

Increased transparency can help to reduce transaction costs and facilitate secondary pipeline capacity trading. There could be net benefits from reforms that aim to increase transparency and facilitate greater secondary pipeline capacity trading. Increased capacity trades, especially those of a short-term nature, could result in a more liquid gas market,

¹⁴ The National Gas Market Bulletin Board, which is operated by the AEMO, was established in 2008 as a gas market and system information website covering the eastern Australian gas market.

potentially promoting investments throughout the supply chain. In particular, entry could be promoted in upstream and downstream markets, benefiting end users.

The COAG Energy Council is consulting with industry on the extent of the information that would be made available on the National Gas Market Bulletin Board. Some stakeholders have expressed concerns with some of the information that has been proposed for public release (ESAA 2014a; Origin Energy 2014a). On the other hand, GDF Suez argued:

Information should be provided to the market and include all significant market data, supply outlook, transport and demand, and should be freely available through a market operator or Gas Bulletin Board. The reforms should follow those established mechanisms in the national electricity market where data is both mandatory and provided on a regimented time line. This approach overcomes the premise that exists today where every item of information must go through a detailed justification on why this is needed in the gas market space. (2014, p. 3)

The extent to which policy reforms would provide net benefits would partly depend on a number of factors. These factors include how much unmet demand there is for capacity in secondary pipeline capacity markets and the costs imposed on gas market participants from increased data-reporting requirements (Alinta Energy 2014; ERM Power 2014a; Origin Energy 2014b). The demand for secondary pipeline capacity trading is expected to increase on some pipelines as physical supply hubs develop and gas markets develop further (AEMO 2012a; ERM Power 2014b). On the costs imposed on market participants, Origin Energy noted:

... we caution against promoting greater transparency purely for transparency's sake. The provision of any gas market information should be accurate and useful for market participants. The cost of providing the information should be proportionate to its considered value and its provision should not erode a market participant's commercial position. (2014b, p. 5)

It is also important to recognise that making public some information may not necessarily provide net benefits to gas users. If there is mandatory disclosure of contractual information, pipeline owners may have incentives to avoid tailoring their service offerings to particular users. Otherwise, other users could demand similar provisions in their contracts (potentially through most favoured nation clauses, where they exist). While standardised service offerings can reduce transaction costs, the potential tradeoff from this is decreased flexibility in the terms and conditions of gas pipeline capacity contracts. As noted by Kalt et al:

In the natural gas pipeline industry, full public disclosure of commercially sensitive pipeline information is not likely to promote the public interest. Requiring pipelines to disclose information believed to be market-sensitive or proprietary will likely harm customers. This will reduce contractual flexibility and narrow customers' options. (1996, p. 63)

The above uncertainties suggest that the intended incremental and light-handed approach to the current reforms will deliver benefits. Importantly, transparency should not be forced simply for its own sake given the potential costs highlighted above. If industry cannot develop solutions to trading unused pipeline capacity, there may be a role for governments

to evaluate the costs and benefits of further reforms. However, any consideration of further change would ideally occur after the current reforms by government and industry have been in place long enough for gas market participants to adjust to the new arrangements, and for the reforms to be properly evaluated.

7 A broad perspective on the case for policy reform

Key points

- Structural adjustment associated with changes in the eastern Australian gas market and concerns about market power are leading to pressure from some gas market stakeholders for policy change.
- The objective of gas market policy reform should be to improve the efficiency of Australia's gas markets. Such an approach would maximise net benefits for the community as a whole.
 - While there are some areas where policy change is warranted, there are areas where governments should resist intervening on the back of incomplete or ambiguous evidence of a policy problem, and where the policy response would be expected to impose net costs on the community.
- Structural adjustment is a pervasive and continuous process that is part of economic development and progress. While structural adjustment imposes costs on some individuals and industries, such movement of resources improves the performance of the economy over time, improving the welfare of the community as a whole. Policies that inhibit structural adjustment are costly and unlikely to be efficient or effective in the long run.
 - A domestic gas reservation policy would impede an efficient adjustment in the structure of the economy in response to higher prices. Distortions in the adjustment of the economy would be compounded over time if investments were made on the basis of gas prices that are below the levels that would have otherwise prevailed in the market.
- Some characteristics of gas markets, such as a small number of participants, could make them vulnerable to anticompetitive behaviour, but this is not conclusive evidence of the existence and exercise of market power.
 - Proposals to address perceived problems with market power should not be introduced unless sufficient evidence has been gathered to demonstrate the existence and exercise of enduring market power, and that the introduction of such proposals would maximise net benefits for the community as a whole. Unnecessarily imposing competition regulation would impose net costs on the community.
 - There is also a need for strong caution when considering applying existing competition law provisions, such as the application of third party access regulation for gas processing facilities.

Structural adjustment associated with changes in the eastern Australian gas market and concerns about market power are leading to pressure from some gas market stakeholders for policy change. In this project, the Commission has examined the rationales for gas

market policy reform, and in so doing has sought to put in a broader context what it considers to be the key areas for policy attention.

7.1 Structural adjustment and policy reform

Structural adjustment is a pervasive and continuous process that is part of economic development and progress. It can be caused by a number of factors, including technological change, policy change and changes in consumer preferences. While structural adjustment entails some costs, such adjustment ultimately improves community welfare by shifting resources to producing goods and services that create more value for consumers and at lower prices. Overall, structural adjustment provides a net benefit to the community.

The linking of the eastern Australian gas market to the Asia–Pacific market has created an opportunity to receive a higher return for domestically produced gas. The community benefits indirectly through the generation of higher income, and from a higher flow of royalty and taxation revenue to governments. Royalty and taxation revenue can subsequently be invested in a range of areas including physical or human capital for the benefit of current and future generations.

Structural adjustment associated with changes in the eastern Australian gas market is placing pressure on some market participants. Some large gas users have reported difficulties in securing gas supply contracts. A further concern relates to the lack of information on existing export commitments and anticipated production levels to gauge how much gas is expected to be available in the eastern market in the future. Some large gas users are concerned that LNG projects may not have sufficient supply to meet their current export contracts, and that this will lead to shortfalls in the eastern market. There is evidence that gas contract prices have increased substantially since 2010, and are likely to continue to rise. The magnitude of the effects will vary across users depending on a number of factors, including: the gas intensity of the user’s current operations; the cost of switching to alternative fuel sources or products (which in some cases is not possible); and (for commercial and industrial users) the capacity to pass on some of the cost increases to consumers.

Policies that inhibit the process of structural adjustment would introduce new barriers to more efficient gas markets, imposing net costs on the community. In particular, preventing gas producers from taking full advantage of an opportunity to receive a higher return from exporting gas produced in Australia, and instead supplying gas to the domestic market, effectively represents a net loss to the community. Reserving gas for the eastern market is just one example of a policy that would impede structural adjustment.

The effects of domestic gas reservation

Recent and prospective increases in gas prices in the eastern Australian gas market have prompted some gas market stakeholders to urge the Australian Government to establish a form of domestic gas reservation policy (box 7.1).

Box 7.1 **Forms of domestic gas reservation**

One proposed form of reservation policy is to require LNG producers to reserve a portion of their production for domestic users (BIS Shrapnel 2014; DomGas Alliance 2012; Manufacturing Australia 2014b; NSW Legislative Council Select Committee 2015). BIS Shrapnel suggested that around 20 per cent of total gas demand (domestic demand plus export demand) would need to be reserved (with the precise amount determined on the basis of forecasted total gas demand). The DomGas Alliance has called for a national reservation policy that is based on the Western Australian Government's reservation policy, which requires LNG producers to reserve 15 per cent of their production for the Western Australian market.¹

The policy provides LNG proponents with some flexibility in the production sources used to meet supply obligations, and supply obligations are only imposed if it is commercially viable to supply the domestic market (EISC 2011). Proponents of the Wheatstone and Pluto LNG projects have committed to eventually supply the equivalent of 15 per cent of LNG production to the domestic market under the policy (EISC 2014). Prior to the introduction of the formal policy in 2006 domestic supply obligations were imposed through state agreements between the Western Australian Government and the proponents of the North West Shelf (in 1979 and 1995) and Gorgon (2003) LNG projects.

The Australian Industry Group (AIG 2013, 2014a) has proposed that a 'national interest test' apply to new or significantly expanded LNG export capacity. The AIG proposed that an expert board conduct open and transparent reviews of new LNG projects before providing a recommendation to the Australian Government Treasurer on whether projects should be approved. In addition to an assessment of whether an LNG project would be in the national interest, the process would require consideration of whether a project would leave adequate gas supply for domestic users and whether the proponents have adequately considered opportunities to supply gas domestically. The AIG said that a national interest test should not interfere with existing contracts and investments.

While the proposals for domestic gas reservation have some differences in policy design, the general economic mechanisms underpinning them are the same. In the short term, reservation would divert gas from LNG production (that would otherwise be exported) to domestic users. With a sufficiently large domestic supply requirement, this would place downward pressure on wholesale gas prices for domestic users, imposing a cost on producers that supply gas to the eastern market. The benefits of reservation would flow directly to gas-intensive industries in the form of lower wholesale gas prices. In a similar

¹ The Queensland Government enacted a formal gas reservation policy in 2011. The explanatory notes for the relevant Bill (Queensland Gas Security Amendment Bill 2011) notes that the policy allows domestic supply conditions to be included in exploration licenses if the Queensland Government's annual Gas Market Review process identifies domestic supply constraints. To date, no domestic supply conditions have been included in exploration licenses.

vein, BIS Shrapnel (2014, p. iv) described national interest tests (such as that used in the United States) as ‘de facto reservation policies’ because they allow governments to limit export volumes and ensure that domestic demand for gas is met.

A domestic gas reservation policy would impede an efficient adjustment in the structure of the economy in response to higher prices in the eastern Australian gas market. The policy would distort the adjustment of the economy by enabling industries that rely on gas prices that are below the market level (either directly through the use of gas or indirectly through linkages in the supply chain), to retain land, labour and capital at the expense of industries that would have otherwise attracted those resources. The higher the percentage of production that is reserved for the domestic market, the greater the distortionary effect of domestic gas reservation.

The distortionary effect of domestic gas reservation would be compounded over time. Domestic gas reservation would lead to investments being made in gas-intensive industries on the basis of gas prices that are below levels that would have otherwise prevailed in the market. Further distortion would arise as companies with significant economic linkages to gas-intensive industries in turn make their own investment decisions.

Some empirical analysis supports the conclusion that domestic gas reservation would impose net costs on the community.

Studies using ‘computable general equilibrium’ (CGE) modelling suggest that restricting LNG exports would impose net costs.² McLennan Magasanik Associates (2009) (commissioned by the Queensland Department of Infrastructure and Planning) estimated that expansion of the LNG industry would increase national real gross domestic product (GDP). ACIL Allen Consulting (2014a) estimated that restricting LNG exports would decrease Australia’s real income. Deloitte Access Economics (2013) (commissioned by the Australian Petroleum Production and Exploration Association) estimated that domestic gas reservation in the eastern Australian gas market would, relative to a scenario where reservation does not apply, decrease annual GDP by \$6 billion in 2025. In a report for the United States Department of Energy, NERA Economic Consulting (2012) estimated that the United States would receive net benefits from expanded LNG exports (box 7.2).

² CGE modelling enables analysis of reservation policies under an empirical framework that allows resources to flow to their highest value use, gas supply to respond to higher prices, gas users to substitute to cheaper inputs (where possible), and for input prices to adjust. While CGE models (and any other modelling framework) cannot provide precise estimates of policy effects, with reasonable assumptions they can provide useful analysis of the likely effects of domestic gas reservation.

To illustrate the mechanisms through which reservation affects market participants, the Commission has estimated the effects of a hypothetical domestic gas reservation policy in a competitive market using its model of the eastern Australian gas market (appendix B).³ Results indicate that a 25 per cent reservation policy with a high LNG price scenario would reduce economic welfare by around \$24 billion over the 20 year modelling period compared to a scenario where there are no reservation requirements. The policy reduces welfare because it diverts the supply of gas from its highest value use, reflected in the higher prices prevailing in the Asia–Pacific market. The policy also reduces investment in new LNG production, which lowers economic output and royalty revenue. Under the central LNG price scenario the policy results in little additional gas supply or price declines for domestic users, and the total decline in economic welfare is around \$2 billion.

Box 7.2 Domestic gas reservation in the United States

Under the United States *Natural Gas Act of 1938*, the Department of Energy must approve projects planning to export LNG to countries that have not signed a free trade agreement with the United States. In deciding whether to approve a project, the Department of Energy must consider whether the project would be in the public interest. The Natural Gas Act creates a presumption that LNG exports would be in the public interest. In assessing whether LNG exports would be in the public interest, the Department of Energy considers a broader range of factors that have been highlighted by the proponents of gas reservation in Australia. These factors include economic effects, international effects, security of natural gas supply and environmental effects, among others (US Department of Energy 2013). The Speaker of the United States House of Representatives has called for geopolitical factors to be considered when approving LNG exports (Boehner 2015).

To inform its assessment of the public interest under the Natural Gas Act, the Department of Energy commissioned NERA Economic Consulting (2012) to estimate the economic effects of LNG exports on the United States. NERA concluded that, under a range of scenarios, LNG exports would deliver net economic benefits to the United States.

Some gas market stakeholders have commissioned studies which showed that domestic gas reservation would deliver a net benefit to the Australian community (box 7.3). However, those studies are based on ‘multiplier’ methodology that assumes that the economy will not adjust to the contraction of a sector and that resources will simply become redundant and will not find alternative uses in other sectors. This approach tends to significantly overestimate the benefits of domestic gas reservation and these studies do not, therefore, provide strong evidence for informing the policy debate.

³ The modelled reservation policy applies to new supply fields, and requires 25 per cent of gas produced in the eastern market to be reserved for users in the eastern market. A lower reservation requirement, for example, 15 per cent or 20 per cent, results in little or no additional gas being supplied to domestic users (and therefore imposes costs for little or no change in market outcomes). Results are reported for the high LNG and central LNG price scenarios, under the low LNG price scenario the policy results in no additional gas being supplied to domestic users. Gas does not need to come from a specific field to meet the policy. The model does not account for gas supply contracts, and does not include income effects from reservation, second round costs of reservation or explicit modelling of other industries as CGE analysis does.

Box 7.3 **Studies used to support calls for domestic gas reservation**

Some gas market stakeholders have commissioned studies that estimate the effect of the expansion of LNG exports on economywide outcomes.⁴ BIS Shrapnel (2014) estimated that a 73.5 petajoule shortfall in gas supply to the manufacturing sector in 2023 would, relative to a scenario where there is no supply shortfall, decrease GDP in 2023 by up to 2.2 per cent. The National Institute of Economic and Industry Research (2012) estimated that expansion of LNG exports from the eastern Australian gas market would, relative to a scenario where there are no LNG exports, reduce GDP in 2040 by around \$22 billion (2009 dollars).

These studies have mainly relied on ‘input-output multipliers’ to estimate the effects of the expansion of the LNG industry. However, multiplier analysis tends to overestimate the benefits of domestic gas reservation. This is because the assumptions underpinning multiplier analysis do not account for a number of important economic effects.

- Labour, land and capital resources released by a decline in gas-intensive domestic industries would be reallocated to other industries over time. Multiplier analysis underestimates the amount of production in the absence of domestic gas reservation by not accounting for increased production in other industries from a reallocation of resources.
- Higher gas prices would encourage greater production and investment in gas exploration and development. Multiplier analysis underestimates the amount of production in the absence of domestic gas reservation by not accounting for increased gas production.
- Higher gas prices would prompt some gas-intensive users to substitute to other energy inputs or adopt more energy efficient production methods, and some users of output produced by gas-intensive industries would substitute to other supply sources. Multiplier analysis overestimates the decline in production in the above industries in the absence of domestic gas reservation by not accounting for these effects.
- In the short term, reduced output in gas-intensive industries would free up inputs such as labour and land, putting downward pressure on the prices of those inputs. Over the longer term, lower input prices would help to facilitate the expansion of other industries. Multiplier analysis underestimates the amount of production in the absence of domestic gas reservation by not accounting for increased production in other industries due to decreased input prices.

Domestic gas reservation may ultimately be costly but ineffective in preventing wholesale gas prices for domestic users in the eastern market from rising in the future. By reducing the return on new supply sources, reservation would decrease incentives to invest in gas exploration and development. The gap created between domestic prices in the eastern market and export prices likely under such a policy would especially weaken incentives to invest in projects that would produce solely for the eastern market, given that all of a domestic project’s production would be sold at prices below the market level.⁵

⁴ Some other empirical studies estimate the effect of the expansion of LNG exports on particular sectors of the economy, such as manufacturing (AEC Group 2012; Deloitte Access Economics 2014).

⁵ BIS Shrapnel (2014) argued that increased gas exploration and development expenditure in Western Australia following the introduction of its formal reservation policy in 2006 is evidence that reservation does not inhibit supply. However, changes in expenditure over time do not provide evidence as to whether expenditure is higher or lower than what it would have otherwise been, and do not account for other factors

The potential effects of domestic gas reservation on supply highlights that such policies are administratively difficult for governments to implement. It would be difficult to forecast the precise amount of gas needed to achieve policy aims, and this amount of gas would change over time due to fluctuations in expected demand. This creates the difficulty of recalibrating the policy on the basis of accurate and updated forecasts of domestic supply and demand without imposing further uncertainty and costs on gas producers. Results from the Commission's model illustrate some of these difficulties, with the effects of reservation on prices and output highly sensitive to the reservation requirement and LNG prices.

7.2 Market power and policy reform

Some gas market stakeholders have argued that gas producers in the eastern Australian gas market have market power, and that the exercise of this power is affecting market outcomes. For example, BIS Shrapnel (2014) said that the market power of gas producers has led to high gas producer profits. The Energy Users Association of Australia (EUAA) said:

Input from EUAA members indicates a strong bias toward the inability to contract competitive terms for gas purchases ... The source of this inability appears to be the manoeuvring by major gas producers to hoard gas and escalate margins using their market power and disproportionate influence. (2014, p. 1)

A number of large industrial gas users have indicated that they are unable to secure contracts at *any* price (or that there is a risk of this happening) (AAC et al. 2014; Dow Chemical 2014; Manufacturing Australia 2012). Some users have suggested that this too is a manifestation of the exercise of market power (AAC et al. 2014). The AIG (2013) undertook a survey of business gas users in the eastern market and found that of businesses looking for new gas contracts, 10 per cent reported they could not get an offer at all (chapter 2). Manufacturing Australia argued:

Australian manufacturers are currently facing export-level prices for future gas contracts, which are approximately double the production cost, with a further risk that gas is not even available for domestic use at any price. Short-to-medium term pressure on domestic pricing is threatening the competitiveness of domestic manufacturers and the high level of value-add provided by these manufacturers. (2012, p. 2)

A comprehensive assessment of the existence and exercise of market power in upstream gas markets is outside the scope of this project. The Commission has not sought to determine, nor has received sufficient evidence to reach any conclusions regarding the existence and exercise of market power in any part of the gas supply chain, and some caution is warranted in drawing firm conclusions on the extent of market power based on evidence that has been put forward to date. However, the Commission has taken on board concerns raised by project participants and others about a lack of effective competition in gas markets, and used

affecting investment, such as exploration costs. Also, the policy would have likely influenced investment before it was formalised in 2006, through the inclusion of supply obligations in state agreements (box 7.1).

the conceptual framework outlined in chapter 2 to make some observations on those concerns in this and the preceding chapters.

Some characteristics of gas markets could (but do not necessarily) make them vulnerable to the presence and exercise of market power. Upstream gas markets in parts of Australia have a small number of suppliers. Joint venture and marketing arrangements that are entered into by gas producers can further increase market concentration. Some companies are also vertically integrated, where a gas explorer is a producer and seller in wholesale and retail markets. Large sunk costs and long investment lags can diminish the threat of entry and the competitive constraint that this can impose on incumbent producers.

However, while market structure is one relevant consideration, it is not of itself sufficient evidence of the existence or exercise of enduring market power. In practice, the ability for gas producers to exercise market power is influenced by a number of factors, including whether users have countervailing power, the existence of economic substitutes for gas (such as household use of electricity), and whether there is a credible threat of entry into the market by new suppliers.

Such countervailing factors are likely to have a greater effect in the long term than the short term. For example, over the longer term, users may be better able to substitute to alternative sources of energy, diminishing any capacity that might exist for gas producers to exercise market power (substitution may be more difficult or impossible when gas is used as a feedstock), and new technologies can be developed to reduce the reliance on the high priced commodity. More fundamentally, even if some gas producers have market power at any given point in time, the associated profits and prices can act as a signal to rivals, with the entry of competitors into the market constraining, and over time eroding, this power.

Further, there can be valid commercial reasons for acquisitions in the gas production sector that increase market concentration — it is not unusual for small speculative explorers to specialise in that activity with the end objective of selling their tenements to a large producer. Also, because gas production costs are relatively high in Australia (McKinsey & Company 2013), acquisitions could be an important means to improving efficiency and competitiveness with gas producers that operate in other countries.

Irrespective of whether there is scope for the exercise of any market power in upstream gas markets, the competitive dynamic is changing due to the linking of the eastern Australian gas market to the Asia–Pacific market. As noted above, higher prices are an expected outcome of this linkage, and can be consistent with outcomes in markets characterised by effective competition. Also, the expectations of higher prices and increased size of the market may be leading to new entry into upstream gas markets, and an increased threat of future entry. The growth of the coal seam gas (CSG) industry in particular appears to have led to considerable new entry in Queensland’s Surat-Bowen basins (AER 2013a).

Prior to the development of gas exports from Queensland, gas prices were relatively stable and low by global standards (AER 2012a; Department of Industry 2013), and contracts for

the supply of gas to domestic users appeared to be easier to secure (Carbon Market Economics 2010). This suggests that higher (and more uncertain) prices and reported difficulties of users in securing contracts may in part be due to current market developments. In particular, producers may be unable to charge prices in the eastern market that are high enough to compensate them for foregone export revenues and other costs of not fulfilling their export contracts, which may not allow for substitution from other sources. Even if prices temporarily exceed the LNG netback price, this may be a reflection of producers managing their risk (including the prospect of penalties and reputational damage for not meeting their export commitments) in a period of market uncertainty (box 3.3). Difficulties for users in securing contracts consequently may be a transitional issue. Uncertainty over future gas prices and the rate of gas production from CSG wells mean it may be commercially rational for gas producers to wait until some of this uncertainty is resolved before committing to terms under a contract.

These observations suggest that policy intervention — which might entail substantial costs — could be aimed at issues that are transitional in nature, or will eventually be resolved efficiently by market participants. Proposals to address perceived problems with market power should not be introduced unless sufficient evidence has been gathered to demonstrate the existence and exercise of enduring market power, and that the introduction of such proposals would maximise net benefits for the community as a whole. Unnecessarily imposing competition regulation would impose net costs on the community. There is also a need for strong caution when considering applying existing competition law provisions, such as the application of third party access regulation for gas processing facilities.

A more comprehensive investigation of market power issues would be required to draw conclusions on whether there is a role for further policy intervention in upstream gas markets. Even if sufficient evidence has been gathered to demonstrate the existence and exercise of enduring market power, the better response may involve the application of competition law, rather than specialised industry restrictions.

The Australian Government's 2014 *Energy Green Paper* canvassed a gas market competition review by either the Australian Competition and Consumer Commission or the Productivity Commission (Department of Industry 2014d).

The effects of third party access regulation for gas processing facilities

There have been calls for policy makers to consider applying third party access regulation, which already applies to gas transmission and distribution pipelines under the National Gas Law, to services provided by gas processing facilities (APA Group 2014; APIA 2014a; DomGas Alliance 2012). The Australian Pipeline Industry Association made the following arguments about the National Access Regime (which the National Gas Law mirrors).

The owner of the gas processing facility is not subject to any access regulation and is able to control the flow of gas out of the facility ... If the National Access Regime were to commence at the entry to the processing facility, third party access to the processing facility itself would be greatly enhanced and competition in the gas supply market would be increased. (2013, p. 6)

Part IIIA of the *Competition and Consumer Act 2010* (Cwlth), which sets out the National Access Regime, contains a number of threshold requirements for its application. These include (among others): a requirement that the declared service is of national significance; a requirement that it is uneconomical to develop another facility; and an exemption for production processes. Regulating access to gas processing services could set a precedent that results in the expanded application of third party access regulation. In its 2013 review of the National Access Regime, the Commission was particularly concerned about proposals to increase the scope of the Regime, including broadening the types of infrastructure services that could be subject to third party access, and made recommendations to further limit the use of the Regime to the exceptional cases where the benefits of regulated access are likely to outweigh the costs.

The Commission has considered the potential reasons for denial of access to processing facilities, and some of the potential costs that third party access regulation could impose.

Potential reasons for denial of access to processing facilities

Owners of gas processing facilities may at times have the ability and incentive to deny access in order to limit competition. In general, incentives to deny access to some or all access seekers will be heightened where infrastructure service providers are vertically integrated — that is, where service providers also operate in markets upstream or downstream of the facility. A number of gas producers also operate in retail markets, providing them with a potential opportunity to deny access and impose higher prices on gas users.

However, in practice the ability to deny access and charge higher prices will be limited if there are constraints on the potential exercise of any market power held by the owners of gas processing facilities. These constraints include the availability of substitute gas processing facilities, the availability of substitutes for gas, users with countervailing power and the threat of entry. The ability to charge higher prices in retail markets is also limited where gas retail prices are regulated (AER 2014).

There could also be valid commercial reasons for the owners of gas processing facilities to deny third party access. For example, as noted above, there is considerable uncertainty regarding future LNG prices and rates of production from CSG wells. It could be commercially rational for gas producers to wait until some of this uncertainty is resolved before relinquishing the real option to use its processing capacity to third parties. Further, providing access to third parties can impose costs on the owners of processing facilities from having to coordinate multiple users. There are costs in ensuring that a facility is compatible with the chemical composition of a third party's gas. More generally, the contractual access rights held by a third party could decrease flexibility in the management of, and investment in, a facility.

Third party access could impose substantial costs

Third party access regulation could impose substantial costs by distorting investment incentives. The ACCC has observed that, in general, many of the potential negative effects on investment from mandating third party access are difficult to avoid:

Due to information constraints and limitations on the regulator's ability to foresee all potential consequences of regulatory decisions, it is not possible to design access regulation that avoids creating any distortions to infrastructure investment incentives. (2013, p. 47)

Access regulation can distort the investment incentives of both owners and potential users of gas processing facilities.

- The investment incentives of gas processing facility owners can be compromised where regulation is expected to expropriate above-normal returns but not compensate for below-normal returns at later points in the supply cycle ('asymmetric truncation'). This asymmetry arises due to the likelihood that third parties will only seek access to gas processing facilities when gas prices are high, leaving the facility owner to bear all of the downside risk associated with its investment. Any 'regulatory risk' associated with access regulation (such as uncertainty regarding future access obligations) could also distort investment incentives.
- Access regulation could reduce the incentives of third parties to invest in infrastructure facilities of their own. While this could help to avoid the duplication of gas processing facilities (and perhaps improve productive efficiency), it also means that access could lock in the infrastructure technology used by the incumbent. There would also be reduced scope for the threat of duplication to improve performance in incumbent facilities.

Further, given that regulators are unable to set optimal access prices (prices that would maximise overall economic efficiency) with precision, there is scope for regulatory error in the setting of access terms and conditions (PC 2013c).

Finally, administrative and compliance costs from access regulation are unavoidable. These include the costs incurred by regulators and businesses when dealing with declaration applications, arbitration proceedings, and reviews of regulatory decisions. The costs associated with government intervention in markets, such as compensatory payments, as well as the costs from companies engaging in strategic behaviour, including through lobbying, are also relevant.

7.3 What role then for policy reform?

The preceding discussion is not to suggest that there is no role for gas market policy reform. On the contrary, the rapid growth and transformation of the eastern Australian gas market places a premium on policies that remove or reduce barriers to more efficient gas markets. The objective of gas market policy reform therefore should be to improve the efficiency of

Australia's gas markets. Such an approach would maximise net benefits for the community as a whole.

To this end, in previous chapters the Commission has outlined some areas where reform may be warranted.

- Allocating gas tenements via cash bidding has theoretical appeal, when compared to the work bidding programs currently in place (chapter 4). However, there are some practical challenges in designing an effective scheme that delivers net benefits. There is merit in observing the operation of cash bidding schemes for petroleum tenements in Queensland and in Commonwealth waters, as well as the operation of cash bidding regimes overseas, to draw lessons on system design and the scope for their broader application.
- Moratoria on CSG activities address concerns about the potential risk to the environment and public health, but also impose costs by potentially locking in higher cost production. They could also increase pressure for other actions by stakeholders that may not necessarily be motivated by the interests of the broader community (chapter 5). The scientific evidence suggests that the technical challenges and risks can be managed through a well-designed regulatory regime, but only if underpinned by effective monitoring and enforcement of compliance. Gas companies should also provide environmental assurance and insurance proportionate to the risk of their activities. If governments seek to impose moratoria or revise land planning protections to favour existing land uses, a transparent consideration of the costs and benefits should be undertaken.
- Some members of the gas industry have had a poor early record of dealing with landholders and local communities. Further thought by explorers and producers on early engagement directly with communities, rather than simply on compensation for landholders, is needed. A well-designed voluntary industry-wide code of practice for community and landholder engagement may improve outcomes. There may also be merit in an independent body to manage the interactions between the industry, landholders and local communities. There is scope for improvements to legislated compensation criteria to better reflect the costs to the landholders from negotiating land access agreements and from the decline in the value of their properties. There is also scope for measures to reduce the transaction costs of negotiating land access agreements including: the development by industry of template agreements and guidance material and, provided the costs are reasonable, the publication of compensation benchmarks by governments.
- There could be net benefits from reforms being implemented by the COAG Energy Council that aim to increase transparency and facilitate greater secondary pipeline capacity trading (chapter 6). The intended incremental and light-handed approach to the current reforms will likely deliver benefits. Any consideration of further change would ideally occur after the current reforms by government and industry have been in place long enough for gas market participants to adjust to the new arrangements, and for the reforms to be properly evaluated.

The effects of linking with the Asia–Pacific market on the Australian economy cannot be ignored. This process increases the imperative for reform in parts of the gas supply chain. The rapid growth and transformation of the market is also magnifying the consequences of any policy errors. Accordingly, the Commission has sounded some notes of caution about introducing policy changes that would impede structural adjustment, or that aim to address the concerns that gas producers can exercise market power (chapter 4 and above) or transmission pipeline markets (chapter 6) on the back of incomplete or ambiguous evidence of a policy problem, or where the policy response would be expected to impose net costs on the community.

A Conduct of the project

In preparing this research paper, the Commission consulted with a range of organisations, individuals, industry bodies, government departments and agencies. The Commission also published information about the project on its website. This appendix lists parties the Commission consulted with through:

- consultations (table A.1)
- a workshop on the Commission's modelling of the eastern Australian gas market, held in Melbourne on 4 February 2015 (table A.2).

Table A.1 Consultations

Organisation

Australian Capital Territory

Australian Aluminium Council
Australian Competition and Consumer Commission (ACCC)
Australian Petroleum Production and Exploration Association (APPEA)
Australian Pipeline Industry Association (APIA)
Department of Industry and the Bureau of Resources and Energy Economics (BREE)
Gas Industry Social & Environmental Research Alliance (GISERA)
Public Health Association of Australia (PHAA)

New South Wales

Argus Media
Australian Energy Market Commission (AEMC)
APA Group
CSR
Independent Pricing and Regulatory Tribunal (IPART)
Origin Energy

Queensland

AgForce Queensland
Department of Natural Resources and Mines
Rio Tinto
QGC
Wagner, Dr Liam (University of Queensland)

(Continued next page)

Table A.1 (continued)

Organisation

South Australia

Santos

Victoria

Australian Energy Market Operator (AEMO)

Australian Energy Regulator (AER)

Australian Industry Group (AIG)

Australian Paper

Department of State Development, Business and Innovation

BHP Billiton

Energy Australia

Energy Users Association of Australia (EUAA)

ExxonMobil

Ferguson, Martin

Grattan Institute

Incitec Pivot

Jemena

Orora Group

Plastics and Chemicals Industry Association (PACIA)

Qenos

Rio Tinto

Victorian Farmers Federation (VFF)

Western Australia

Alcoa

Woodside Petroleum

Table A.2 Workshop participants — Melbourne, 4 February

<i>Organisation</i>	<i>Participants</i>
AGL Energy	Tim Nelson
Australian Industry Group (AIG)	Tennant Reed
APA Group	Stephen Livens
Australian Aluminium Council (AAC)	Miles Prosser
Australian Energy Market Commission (AEMC)	Leah Ross Steven Bond-Smith
Australian Energy Market Operator (AEMO)	Scott Maves
Australian Energy Regulator (AER)	Anthony Bell
Australian Paper	Brian Green
Australian Petroleum Production & Exploration Association (APPEA)	Larissa Wood
Australian Pipeline Industry Association (APIA)	Steve Davies
BHP Billiton	Jarrold Ball Isaac Hinton
Core Energy Group	Paul Taliangis
Department of Economic Development, Jobs, Transport and Resources (Victorian Government)	Linda Bibby Simon McCabe
Department of Energy and Water (Queensland Government)	Sean Proctor
Department of Industry (Australian Government)	Ross Lambie David Whitelaw
Energy Supply Association of Australia (ESAA)	Shaun Cole
Energy Users Association of Australia (EUAA)	Phil Barresi
EnergyAustralia	Steve Wright
EnergyQuest	Graeme Bethune
Epic Energy	Jonathan Teubner
Geoscience Australia	Steve Cadman
Grattan Institute	David Blowers
Incitec Pivot	Tim Lawrence
Jemena	Gabrielle Sycamore Benjy Lee
NSW Trade and Investment (NSW Government)	Kate Norris
Origin Energy	Russel Pendlebury
Orora	Peter Dobney
Plastics and Chemicals Industry Association (PACIA)	Peter Bury
Qenos	Andrew Cheah
QGC	Erin Bledsoe Adam Crudden
Rio Tinto	Mark Grenning
Santos	Matt Sherwell
University of Sydney	Gordon MacAulay

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