



Australian Government
**Bureau of Resources
and Energy Economics**

Gas Market Report

July 2012



bree.gov.au



Australian Government
**Bureau of Resources
and Energy Economics**

Gas Market Report

July 2012

bree.gov.au

Copeland, A., Grafton, Q., Hitchins, N., and Syed, A., 2012

BREE Gas Market Report 2012, BREE, Canberra, May.

Authors listed in alphabetical order.

© Commonwealth of Australia 2012



About the Bureau of Resources and Energy Economics

The Bureau of Resources and Energy Economics (BREE) is a professionally independent, economic and statistical research unit within the Australian Government's Resources, Energy and Tourism (RET) portfolio. The Bureau was formed on 1 July 2011 and its creation reflects the importance placed on resources and energy by the Australian Government and the value of these sectors to the Australian economy.

BREE's mission is to support the promotion of the productivity and international competitiveness of Australia, the enhancement of the environmental and social sustainability, and Australia's national security within the resources and energy sectors. To this end, BREE uses the best available data sources to deliver forecasts, data research, analysis and strategic advice to the Australian government and to stakeholders in the resources and energy sectors.

The Executive Director/Chief Economist of BREE is Professor Quentin Grafton. He is supported by a dedicated team of resource and energy economists as well as an advisory board. The board is chaired by Drew Clarke, the Secretary of the Department of Resources, Energy and Tourism, and includes prominent Australian experts from both the private and public sectors.

The BREE team has an in-depth knowledge of resources and energy from both an Australian and a global perspective. The staff at BREE work across the areas of resources, energy and quantitative analysis, data and statistics and modelling and policy integration. The team has a range of skills across several disciplines and subject areas including: applied resources and energy economic research; policy analysis; microeconomic analysis; macroeconomic and market analysis; applied mathematics and mathematical modelling; statistical and econometric analysis and forecasting, and scenario and risk analysis.

978-1-922106-22-3 BREE - Gas Market Report July 2012 (Print)

978-1-922106-23-0 BREE - Gas Market Report July 2012 (PDF)

For more information on BREE and what it does, please visit www.bree.gov.au or contact BREE by mail, telephone or email.

Postal address:

Bureau of Resources and Energy Economics

GPO Box 1564

Canberra ACT 2601 Australia

Phone: +61 2 6276 1000

Email: info@bree.gov.au

Web: www.bree.gov.au

Acknowledgments

BREE thanks colleagues within the Energy Division, the Resources Division and the Energy White Paper team of the Australian Government Department of Resources, Energy and Tourism (RET) for their very valuable contributions to this report. BREE thanks Geoscience Australia (GA) for its estimates of Australian gas reserves.

BREE is grateful for work on early drafts by Adrian Waring (former BREE colleague) and for the insightful comments of Ian Cronshaw of RET and the International Energy Agency (IEA) and Professor Ronald D. Ripple of Curtin University on an earlier version of this report.

Executive summary

This BREE Gas Market Report is a desktop study structured in three main parts: an overview of global and domestic gas markets; the issues of supply and demand and how gas is priced; and projections of domestic gas prices.

BREE expects that global gas production, consumption and trade will increase over the next two decades. In OECD economies increased gas consumption will be underpinned by the use of gas as a relatively clean fossil fuel for electricity generation. In non-OECD economies gas consumption will be underpinned by the use of gas in expanded electricity generation as a number of economies seek to diversify electricity generation away from coal.

Australia has important conventional and unconventional gas reserves and is, presently, the world's fourth largest exporter of LNG. Strong growth in domestic and global demand for gas is expected to underpin the development of new gas fields and LNG capacity in Australia. Based on the projects currently in operation, and those that are committed or under construction, Australia's LNG exports are projected to increase from about 20 million tonnes to over 63 million tonnes annually by 2016–17.

In Australia, gas consumption is projected to increase over the next two decades as a carbon price increases the competitiveness of gas fired electricity generation relative to coal. However, the big transformation in Australia's gas industry will come via a rapid increase in LNG exports from the middle of this decade.

Increases in LNG exports from Australia, particularly with the commencement of exports from the Eastern market, are likely to have substantial implications for gas prices in this market. These include:

- Eastern market wholesale gas prices are projected to rise sharply over the short to medium term as prices converge towards LNG netback prices in anticipation as gas exports beginning in 2014 and because of temporary gas supply constraints as CSG gas wells ramp up to full production;
- Gas demand is relatively price inelastic and the effect of increased gas prices on consumption is projected to differ across sectors. Responses to higher gas prices are expected to be greatest in gas-intensive industries; and
- The linkage between the Eastern market and international gas markets along with a competitive domestic gas market should support investment in gas supply and, ultimately, increase the production of gas in Eastern Australia.

Contents

Acknowledgments	iii
Executive summary	iv
List of acronyms	viii
1. Introduction	1
2. International gas markets	2
Reserves and resources	2
Consumption	7
Non-OECD consumption	10
OECD consumption	11
Production	11
Non-OECD production	13
Trade	15
Trade in Asia-Pacific	16
Trade in North America	18
Australian trade	21
3. The Australian gas markets	23
Reserves and resources	23
Australia's gas infrastructure network	25
Consumption	26
Production	29
Exports	31
Market structure	32
Western market	32
Northern market	34
Eastern market	35
4. LNG pricing and marketing	40
Spot markets and short term contracts	40
Long and medium term contracts	40
Gas-on-gas indices	41
Competing fuel indices – oil linked pricing	41
Outlook for gas prices	43
5. Tightening of the domestic eastern gas market	45
6. Domestic gas prices	48

Factors determining domestic gas prices	48
Expiration and renegotiation of long-term contracts	50
Increasing domestic and export demand for gas	51
Increasing production costs	53
Constraints on CSG production	56
Streamlining of CSG regulatory control	57
Increasing network charges	57
Market competition and transparency	58
Australian gas reservation policies	59
Economics of domestic gas reservation	59
Gas price projections	60
ACIL Tasman gas price assumptions	60
IES/AEMO gas price assumptions 2011	62
ACIL Tasman	63
Australian Treasury gas price assumptions 2011	64
Summary of gas price assumptions	64
7. Conclusions	66
Glossary	68
References	71
Annex	74
Figures	
Figure 2.1: World natural gas resources by major region	3
Figure 2.2: Hydraulic fracturing	5
Figure 2.3: Change in natural gas production by country (New Policies Scenario)	12
Figure 2.4: US LNG export prices to Asia	20
Figure 2.5: Australian and world LNG export capacity	21
Figure 3.1: Australia's EDR of gas	24
Figure 3.2: Australia's gas balance to 2034-35	25
Figure 3.3: Australian gas basins and transmission pipelines	26
Figure 3.4: Australian primary consumption of gas by sector in 2009-10	27
Figure 3.5: Total primary energy supply: 2008-09 and 2034-35	28
Figure 3.6: Overview of Australia's LNG production capacity	32
Figure 3.8: Western market primary consumption of gas by sector in 2009-10	33
Figure 3.9: Northern market primary consumption of gas by sector in 2009-10	35
Figure 3.10: Eastern market primary consumption of gas by sector in 2009-10	37

Figure 3.11: CSG and natural gas production in Australia	38
Figure 4.1: Regional gas and oil prices	44
Figure 6.1: Average 2010 wholesale gas price by country	49
Figure 6.2: Eastern market retail gas price index	50
Figure 6.3: East coast domestic gas contracts	50
Figure 6.4: Oil linked LNG netback prices to the Eastern market	52
Figure 6.5: Henry Hub linked LNG netback prices to the Eastern market	53
Figure 6.6: Estimated Eastern gas production costs per GJ	54
Figure 6.7: Estimated Eastern market gas production costs (Core Energy 2012)	55
Figure 6.8: Effect of increases in wholesale gas costs on retail costs	56
Figure 6.9: The effects of higher network charges on retail gas prices (nominal)	58
Figure 6.10: Representative gas price projections used for AEMO planning scenarios	62
Figure 6.11(a) Gas price assumptions 2012	63
Figure 6.11 (b) Gas price assumptions 2020	63
Figure 6.11 (c) Gas price assumptions 2030	64

Tables

Table 2.1: Recoverable resources of gas and indicative production costs, January 2010	2
Table 2.2: Proved gas reserves and shale gas resources (tcm)	6
Table 2.3: Primary natural gas demand by region and scenario (trillion cubic metres)	9
Table 2.4: Average annual growth rates of gas consumption from 2009 to 2035	9
Table 2.5: Major LNG exporters, 2010	16
Table 2.6: Applications received by DOE to export US produced LNG, as of early May 2012	20
Table 3.1: Australia's gas resources	23
Table 3.3: Completed CSG/gas-fired electricity generation projects since October 2008	29
Table 3.4: Australian gas production by field in 2010–11 a	30
Table 6.1: Breakdown of retail gas prices in NSW	55
Table 6.2: Projected gas prices, 2010\$/GJ	61
Table 6.3: Projected Eastern market gas prices, 2012-13\$/GJ	61
Table 6.4: Projected gas prices, 2012-13 \$/GJ	61
Table 6.5: Summary of gas price assumptions by various analysts, 2011–12 dollars	65
Table A1: Australian LNG projects in operation, under construction or planned	74

Boxes

Box 2.1: Shale gas	4
Box 2.2: Will China replicate the US shale gas experience?	14
Box 2.3: Attitudes towards unconventional gas production in the OECD	15

List of acronyms

AEMO	Australian Energy Market Operator
BREE	Bureau of Resources and Energy Economics
CSG	coal-seam gas
DOE	US Department of Energy
EDR	economic demonstrated resources
EIA	Energy Information Administration
EPBC Act	<i>Environmental Protection and Biodiversity Act 1999</i>
FTA	free trade agreement
GA	Geoscience Australia
GBRWhA	Great Barrier Reef World Heritage Area
GBRMPA	The Great Barrier Reef Marine Park Authority
GSOO	Gas Statement of Opportunities
IEA	International Energy Agency
IES	Intelligent Energy Systems
JCC	Japan Customs-cleared Crude
LNG	Liquefied natural gas
NEM	National Energy Market
NWS	North West Shelf
OECD	Organisation for Economic Cooperation and Development
QGS	Queensland Gas Scheme
RET	Department of Resources, Energy and Tourism
UNESCO	United Nations Educational, Scientific and Cultural Organization
USGS	United States Geological Survey

Useful approximations for gas conversions

From	To	mmcm	bcm	tcm	mmcf	bcf	Mt LNG	GJ	TJ	PJ	MMBtu
mmcm	Multiply by:	1	0.001	1.00×10^6	35.31	3.53×10^{-2}	7.35E-04	38800	38.80	3.88×10^{-2}	36775
bcm		1000	1	1.00×10^3	35313	35.31	0.735	3.88×10^7	38800	38.80	3.68×10^7
tcm		1.00×10^6	1000	1	3.53×10^7	35313	735	3.88×10^{10}	3.88×10^7	38800	3.68×10^{10}
mmcf		0.028	2.83×10^{-5}	2.83×10^{-8}	1	1.00×10^{-3}	2.08×10^{-5}	1099	1	1.10×10^{-3}	1041
bcf		28.32	0.028	2.83×10^{-5}	1000	1	0.021	1.10×10^6	1099	1.099	1.04×10^6
Mt LNG		1361	1.361	1.36×10^{-3}	48045	48.04	1	5.28×10^7	52787	52.79	5.00×10^7
GJ		2.58×10^{-5}	2.58×10^{-8}	2.58×10^{-11}	9.10×10^{-4}	9.10×10^{-7}	1.89×10^{-8}	1	1.00×10^{-3}	1.00×10^{-6}	0.948
TJ		0.026	2.58×10^{-5}	2.58×10^{-8}	0.910	9.10×10^{-4}	1.89×10^{-5}	1000	1	1.00×10^{-3}	948
PJ		25.77	0.026	2.58×10^{-5}	910	0.910	0.019	1.00×10^6	1000	1	9.48×10^5
MMBtu		2.72×10^{-5}	2.72×10^{-8}	2.72×10^{-11}	9.60×10^{-4}	9.60×10^{-7}	2.00×10^{-8}	1.055	1.06×10^{-3}	1.06×10^{-6}	1

Abbreviations

mmcm	million cubic metres
bcm	billion cubic metres
tcm	trillion cubic metres
mmcf	million cubic feet
bcf	billion cubic feet
Mt	million tonnes
GJ	gigajoule
TJ	terajoule
PJ	petajoule
MMBtu	million British thermal units
LNG	liquefied natural gas

Notes:

1. To convert 10 Mt of LNG into million cubic metres, multiply by 1361

10Mt LNG = 13610 million cubic metres of gas

2. 1 million cubic metres = 10^6 x 1.0 cubic metre (m^3)
3. 1 billion cubic metres = 10^9 x 1.0 cubic metre (m^3)
4. 1 trillion cubic metres = 10^{12} x 1.0 cubic metre (m^3)
5. 1 gigajoule = 10^9 x 1.0 joule (J)
6. 1 terajoule = 10^{12} x 1.0 joule (J)
7. 1 petajoule = 10^{15} x 1.0 joule (J)
8. 1 British thermal unit = 1055 joules (J)
9. 1 tonne = 10^3 x 1.0 kilogram (kg) = 2205 pounds (lbs)

I. Introduction

This is the first of what is planned to be an annual report on the current state and projected developments in international and domestic gas markets. In this, the 2012 issue, the focus is on gas supply and demand and the implications for gas prices, especially in the Eastern market of Australia.

As the world moves towards a lower carbon economy, gas is expected to become the fuel of choice, particularly for electricity generation. In emerging economies, gas is an especially attractive fuel for economies that are seeking to satisfy rapid growth in fast growing cities. Increases in gas consumption in emerging economies are expected as a result of robust economic growth, on-going urbanisation and industrialisation, and strong growth in electricity demand and direct gas consumption for electricity generation.

While production from regions such as the Russian Federation, China, Qatar and the US is projected to continue to underpin world supply of gas, Australia is set to play an increasingly important role in global gas markets. Australia is on track to becoming the world's second largest exporter of liquefied natural gas (LNG) by as soon as 2015.

Australia's LNG projects connect its domestic gas markets to international gas markets and increase the competition for domestic gas. The advent of LNG has transformed the Western gas market (Western Australia), and underpinned the development of their reserves. The rise of Australian coal-seam gas (CSG) as a feedstock for LNG exports out of Gladstone in Queensland will substantially change the Eastern gas market (Queensland, New South Wales, Victoria, South Australia, Australian Capital Territory and Tasmania).

The 2012 BREE Gas Market Report is a desk-top study and is structured in three main parts: an overview of global and domestic gas markets; the issues of supply and demand and how gas is priced; and projections of gas prices. Section 2 briefly describes the international gas markets while Section 3 presents an overview of the Australian gas markets. Section 4 outlines LNG pricing mechanisms and the price outlook for LNG. Section 5 analyses the potential tightening of the Eastern Gas market in the short to medium term while Section 6 reviews the factors affecting domestic gas prices and presents price projections. Section 7 offers concluding remarks.

2. International gas markets

Reserves and resources

As at the end of 2010, conventional proved world gas reserves—the quantity that can be recovered in the future from known reservoirs under existing economic and operating conditions—are estimated to be 187 trillion cubic metres (tcm), or 59 years of production at 2010 production levels (BP 2011).

The world's remaining recoverable resources of gas—the quantity that are recoverable using existing technology, at current prices—are estimated by the International Energy Agency (IEA) to be 810 tcm, or over 250 years of production at 2010 production levels (IEA 2011a, 2011c).

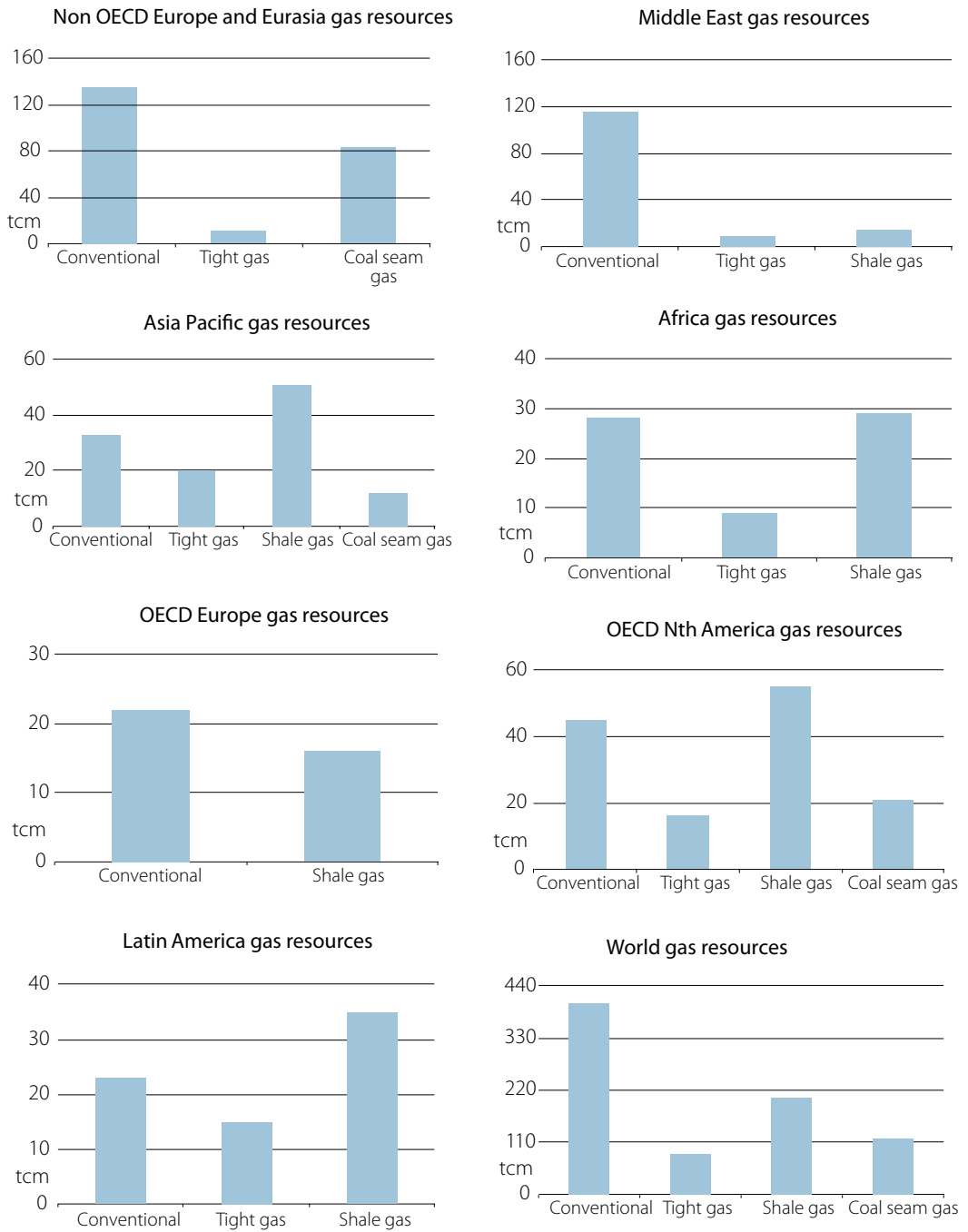
In general, unconventional gas resources—those found in coal seams, shale layers or tightly compacted sandstone—are more widely dispersed than conventional resources. Around 14 per cent of the world's remaining recoverable gas resources are located in the Asia-Pacific region, and the majority of those resources are unconventional gas (see Table 2.1 and Figure 2.1).

Table 2.1: Recoverable resources of gas and indicative production costs, January 2010

Region	Conventional		Tight Gas		Shale Gas		CSG	
	tcm	US\$/GJ	tcm	US\$/GJ	tcm	US\$/GJ	tcm	US\$/GJ
Non-OECD Europe and Eurasia	136	2-6	11	3-7			83	3-6
Middle East	116	2-7	9	4-8	14			
Asia-Pacific	33	4-8	20	4-8	51		12	3-8
OECD North America	45	3-9	16	3-7	55	3-7	21	3-8
Latin America	23	3-8	15	3-7	35			
Africa	28	3-7	9		29			
OECD Europe	22	4-9			16			
World	404	2-9	84	3-8	204	3-7	118	3-8

Source: IEA (2011c)

Figure 2.1: World natural gas resources by major region



Source: IEA 2011c

While assessments of the world's unconventional resources are limited, comparatively more information is available on shale gas. The US Energy Information Administration (EIA) estimates that the identified technically recoverable shale gas resources—the quantity that are recoverable using existing technology, regardless of cost—of select basins across fourteen regions is around 188 tcm (EIA 2011b). Of these fourteen regions, the vast majority of shale gas resources are thought to be located in China, followed by the US, Argentina and Mexico (see Table 2.2).

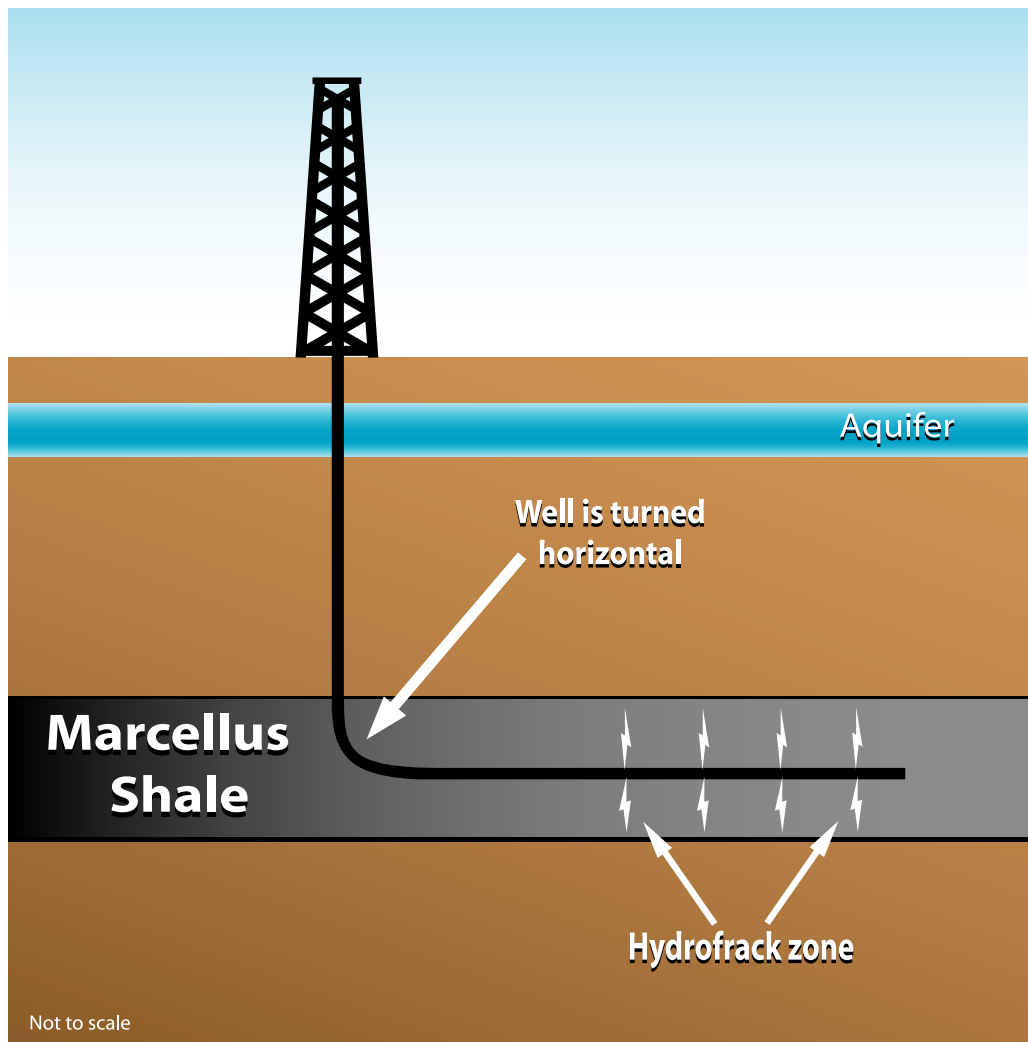
Box 2.1: Shale gas

Shale gas is a type of unconventional gas that has not travelled to a reservoir rock, but is still contained within organic-rich source rocks such as shales and fine-grained carbonates. The gas contained within the shale has low permeability and conventional extraction techniques would yield low rates of production and be uneconomic. The production of shale gas has increased rapidly in the US over the past five years following technological advances that have allowed for horizontal drilling and hydraulic fracturing to be used together. Combined use of these two technologies has enhanced the economic viability of shale gas production and allowed production to increase from 64 billion cubic metres (bcm) in 2008 to 139 bcm in 2010.

Individually, horizontal drilling and hydraulic fracturing have long been used by the oil and gas industry. The joint application of technology to the shale gas reserves was brought about by very high gas prices in the US associated with a gradual decline in conventional gas production. Horizontal drilling is used to enhance the access to the gas within the shale. A well is first drilled vertically until it reaches a certain depth, at which point the drilling changes to the horizontal plane through the shale. Drilling horizontally enhances exposure of the production casing to the source rock holding the gas. Hydraulic fracturing is the process of injecting a mixture of water, chemicals and sand into the shale to fracture it, thereby releasing the gas that is contained within. The combination of these two technologies significantly enhances the flow of the trapped gas.

The development of shale gas in the US has been enhanced by the existence of the necessary pipeline infrastructure, competitive and efficient market structures (including third party access) and an established support services sector located in regions close to where the shale reserves are located.

Figure 2.2: Hydraulic fracturing



Shale gas exploration is still at an early stage in many regions including China and Latin America. As a result, there is a high degree of uncertainty around global estimates of the total resources of unconventional gas. Nevertheless, it is likely that as information on the size and production characteristics of shale gas resources in several regions around the world improves, this will add to global estimated gas reserves.

Table 2.2: Proved gas reserves and shale gas resources (tcm)

	Proved gas reserves	Technically recoverable shale gas resources
Europe		
France	0.0	5.1
Germany	0.2	0.2
Netherlands	1.4	0.5
Norway	2.0	2.4
U.K.	0.3	0.6
Denmark	0.1	0.7
Sweden	0.0	1.2
Poland	0.2	5.3
Turkey	0.0	0.4
Ukraine	1.1	1.2
Lithuania	0.0	0.1
Others	0.1	0.5
North America		
US	7.7	24.4
Canada	1.8	11.0
Mexico	0.3	19.3
Asia		
China	3.0	36.1
India	1.1	1.8
Pakistan	0.8	1.4
Australia	3.1	11.2
Africa		
South Africa	0.0	13.7
Libya	1.5	8.2
Tunisia	0.1	0.5
Algeria	4.5	6.5
Morocco	0.0	0.3
Western Sahara	0.0	0.2
Mauritania	0.0	0.0
South America		
Venezuela	5.1	0.3
Colombia	0.1	0.5
Argentina	0.4	21.9
Brazil	0.4	6.4
Chile	0.1	1.8
Uruguay	0.0	0.6
Paraguay	0.0	1.8
Bolivia	0.8	1.4
Total of above countries	36.1	187.5
World	187.2	na

Source: EIA, 2011b

Estimates of shale gas resources are complicated by the different methods used for estimation. For example, EIA estimates are based on a volumetric method which derives resource volumes for a given sedimentary basin based on the area, thickness, porosity, hydrocarbon saturation, source rock potential and pressure of the prospective formation. These estimates are then adjusted by applying bulk success and recovery factors, determined from existing exploration data and/or geological inferences.

The volumetric method is likely to overestimate the technically recoverable shale gas resource potential of countries with undeveloped unconventional gas reserves, such as China. This is because to what extent the volumetric resource potential will be realised depends on the topography, water availability, infrastructure, depth of the resource and complexity of the tectonic structure. These factors are thought to be more challenging in China, relative to North America. This, in turn, may increase the cost and the time to develop shale gas in China, and also in other countries that do not have existing gas infrastructure.

The United States Geological Survey (USGS) uses a probabilistic method to estimate resources that differs to the approach used by the EIA. The USGS method takes into account the likely productivity of individual wells within a sedimentary basin to calculate the total estimated ultimate recovery for the basin as a probability distribution. Productivity estimates on which the estimated resource is calculated are derived from a comprehensive body of North American exploration and production data. The USGS considers productivity-based methods to be more realistic than the volumetric method.

The USGS is currently collaborating internationally with geoscientific research organisations, including GA, with the aim of estimating global unconventional gas resources using the probabilistic method.

Consumption

Gas is an important global energy source and accounted for 21 per cent of global energy consumption in 2010 (IEA 2011d). The four largest gas consumers are the US (21 per cent of global gas consumption), the Russian Federation (14 per cent), Iran (4 per cent) and China (3 per cent) (IEA 2011b). Over the past ten years, global gas consumption increased at an average annual rate of 2.9 per cent and totalled 3.4 tcm in 2011 (IEA 2011b, IEA 2012). These trends are expected to continue over the medium term, with the IEA projecting world gas consumption to reach 3.9 tcm by 2017 (IEA 2012). Historical and projected increases in gas consumption reflect greater use of gas in electricity generation, industrial production and in the residential sector.

Gas-fired electricity generation is, typically, characterised by lower capital expenditures, shorter construction times, greater flexibility in meeting peak demand, lower carbon emissions and higher thermal efficiencies relative to other substitute fossil fuels. Gas-fired electricity can also complement renewable energy sources, and help to overcome intermittency problems associated with renewable energy sources such as solar and wind.

While the majority of global increases in gas demand are projected to come from electricity generation, this will depend on the price of gas relative to substitute fuels, as well as domestic

policy settings regarding nuclear energy, renewable energy and carbon pricing as well as other carbon limiting regulations or measures.

Global gas demand over the medium and long term is expected to increase strongly (see Tables 2.3 and 2.4)—with particularly robust growth projected in emerging economies, including China. The IEA projections of global and regional gas consumption to 2035 were developed for four policy scenarios, which are detailed below.

1. IEA New Policies Scenario (the reference case):

This scenario incorporates broad policy commitments and plans that have been announced by countries to address energy security, climate change, local pollution and other pressing energy related challenges, even when the specific measures to implement these commitments have yet to be announced.

2. IEA Golden Age of Gas Scenario

The Golden Age of Gas Scenario takes the New Policies Scenario in the World Energy Outlook 2010, as its starting point, but incorporates some different assumptions about policy, prices and other drivers that could influence gas demand and supply over the outlook period. It takes into account China's ambitions outlined in its 12th five year plan to achieve an 8.3 per cent share for natural gas in its overall energy mix by 2015. This scenario assumes that there will be lower global nuclear power generation capacity in the future as a result of changes in government policy following the disaster at the Fukushima nuclear power plant in Japan. This scenario also assumes increased use of gas in the transport sector, and that gas prices remain lower than those assumed in the 2010 New Policies Scenario.

3. IEA Current Policies Scenario:

This scenario shows how the future might look on the basis of the continuation, without change, of government policies and measures that had been enacted or adopted by mid-2011.

4. IEA 450ppm Scenario:

This scenario sets out an energy pathway that is consistent with a 50 per cent chance of meeting the goal of limiting the increase in average global temperature to two degrees Celsius compared with pre-industrial levels.

For further details on the above four scenarios please refer to the IEA (www.iea.org).

Table 2.3: Primary natural gas demand by region and scenario (trillion cubic metres)

	1980	2009	New Policies Scenario		Golden Age of Gas Scenario		Current Policies Scenario		450 ppm Scenario	
			2020	2035	2020	2035	2020	2035	2020	2035
OECD	1.0	1.5	1.7	1.8	1.7	2.0	1.7	1.9	1.6	1.5
Non-OECD	0.6	1.6	2.2	2.9	2.3	3.2	2.2	3.2	2.1	2.4
World	1.5	3.1	3.9	4.8	4.0	5.1	3.9	5.1	3.7	3.9
Share of non-OECD	37%	51%	56%	61%	58%	62%	56%	62%	56%	62%

Source: IEA 2011a, IEA 2011c

Table 2.4: Average annual growth rates of gas consumption from 2009 to 2035

	New Policies Scenario	Golden Age of Gas Scenario	Current Policies Scenario	450ppm Scenario
OECD	0.7%	1.0%	0.9%	-0.1%
Non-OECD	2.4%	2.8%	2.8%	1.7%
World	1.7%	2.0%	2.0%	0.9%

Source: IEA 2011a, IEA 2011c

Gas is the only fossil fuel for which global consumption rises under all four scenarios. Consumption of gas in the 450ppm Scenario, however, is lower than the Current Policies Scenario, partly as a result of lower projected demand for electricity and stronger additional policy action to reach the goal of limiting the rise in greenhouse gas emissions (IEA 2011a). Gas consumption under the New Policies Scenario is higher than the Current Policies Scenario because of assumed new measures that favour gas use relative to other fossil fuels, such as stricter regulation of emissions and pollutants (IEA 2011a). Under the New Policies Scenario, the share of gas in the global energy mix rises from 21 per cent in 2009 to 23 per cent in 2035 (IEA 2011a).

Gas consumption in the electricity generation sector is projected to account for the largest share of this growth and is projected to increase at an average annual rate of 1.8 per cent to 2035 (IEA 2011a). Increases in direct gas consumption in buildings, industry and transport are also projected to occur, but this is expected to be less important than growth of gas consumption in the power sector.

Much of the growth in gas consumption is projected to occur in emerging economies, where gas-fired energy is projected to support strong economic growth. An expanded gas distribution network could accelerate a switch away from more expensive heating fuels commonly used in these economies, such as kerosene. Demand for gas in more mature OECD markets, however, is projected to increase only moderately between 2009 and 2035 due to the already relatively high share of gas used in the electricity generation sector (IEA 2011a). Projections of gas consumption and production in the following section are results based from the New Policies Scenario.

Non-OECD consumption

Non-OECD gas consumption in 2011 increased by 4.2 per cent relative to 2010, to total 1.77 tcm (IEA 2012). China's growth in gas consumption was the greatest of any economy, increasing by 20 per cent in 2011 to reach around 130 bcm (IEA 2012).

Non-OECD countries are projected to account for around 80 per cent of demand growth to 2035. Gas consumption in these countries is projected to grow by an average of 2.4 per cent a year to total 2.9 tcm in 2035. The highest growth in consumption to 2035 is projected to occur in China and Brazil (IEA 2011a).

Economic growth and energy policies in non-OECD economies will be the key determinants of their future gas consumption. In emerging economies, where increased rates of urbanisation and industrialisation are projected, an increased demand for consumer durables and machinery will support higher gas-fired electricity consumption. Policies that encourage diversification within the energy mix also tend to favour higher gas consumption, at least in the medium term, as governments attempt to shift their respective economies away from a reliance on other more carbon intensive fossil fuels. Gas-fired electricity will also be increasingly used to complement renewable energy sources to mitigate intermittency problems.

Recent energy-related policy developments in China—particularly those outlined in its 12th Five Year Plan (2011–2015)—have the potential to support further growth in gas demand. In particular, China's policy makers are actively encouraging diversification of the electricity generation fuel mix away from coal, towards gas, renewable energy sources and nuclear power (IEA 2011a).

According to the IEA, the Chinese Government aims to increase the share of gas in domestic energy consumption to 8.3 per cent of the total in 2015 by promoting gas use in electricity generation, transportation and for residential use (IEA 2011c). China's domestic production is projected to increase by around 60 per cent between 2010 and 2016. However, increases in production are projected to account for only around half of incremental increases in demand, with the deficit made up with imports (IEA 2011e).

Over the medium-to-longer term, growth in China's gas consumption will be supported by continued strong economic growth and associated urbanisation and industrialisation, and robust growth in electricity demand and direct gas consumption. In the IEA's New Policy Scenario, China's gas consumption is projected to grow at 6.7 per cent a year to total 502 bcm in 2035 (IEA 2011a). From 2009 to 2035, China is expected to account for a quarter of global gas demand growth.

The Indian Government, like China's, plans to increase the share of gas in the energy mix of its economy. India's consumption is projected to grow from 59 bcm in 2009 at an average annual rate of 4.5 per cent to total 186 bcm in 2035. By 2035, gas is projected to account for 11 per cent of total primary energy consumption (IEA 2011a).

In the Middle East, gas has become the preferred fuel for power generation, substituting for oil in many cases. In turn, this has allowed for higher oil exports than would otherwise have been the case. Gas consumption in the Middle East is projected to grow at an average annual rate of 2.3 per cent to 622 bcm in 2035 (IEA 2011a).

OECD consumption

Over the last ten years, gas has been the predominant fuel of choice for incremental electricity generation in OECD economies. This is projected to continue over the medium to long term, but gas consumption in the OECD is only projected to grow at an average annual rate of 0.7 per cent between 2009 and 2035 to total 1.8 tcm (IEA 2011a).

Gas demand in OECD Europe is projected to increase at an average annual rate of 0.9 per cent to reach 671 bcm in 2035. The German government's decision to close 17 nuclear power plants over the next ten years and replace the lost capacity with gas-fired electricity generation and renewable energy is expected to support European gas demand over the outlook period.

In OECD America gas demand is projected to increase at an average annual rate of 0.6 per cent to 951 bcm in 2035. Growth in gas demand will be underpinned by relatively low gas prices which encourage gas consumption in preference to other fossil fuels, particularly for electricity generation.

In OECD Asia-Pacific (Japan, South Korea, Australia and New Zealand) gas demand is projected to increase by 1 per cent a year to reach 219 bcm by 2035. In this region, gas is expected to remain an important fuel for electricity generation and industrial and domestic consumption. Projected increases in Japan's gas consumption are highly dependant on the outcome of ongoing policy discussions regarding the future of nuclear energy and its role in Japan's energy mix.

Production

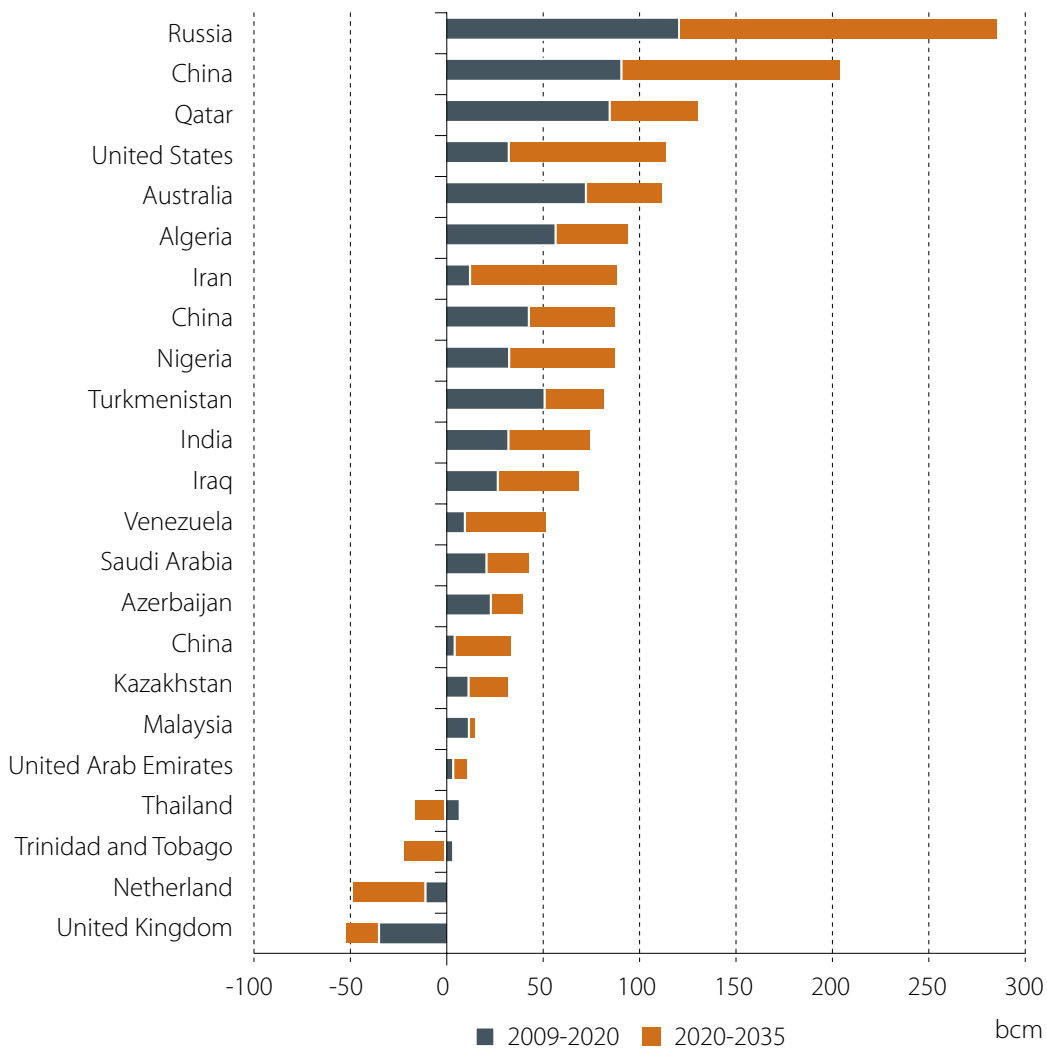
Global gas production totalled 3.4 tcm in 2011 (IEA 2012). Almost two thirds of the world's gas was produced in non-OECD countries. Global gas production is projected to increase at an average annual rate of 1.7 per cent to total 4.8 tcm in 2035 (IEA 2011a).

According to the IEA, the United States was the largest producer of gas in 2011 (653 bcm), followed by the Russian Federation (651bcm), and Canada a distant third (161 bcm) (IEA 2012).

The share of unconventional gas in total global gas production is projected to rise from 13 per cent in 2009 to 22 per cent in 2035 (IEA 2011a). However, these projections are subject to a great deal of uncertainty, particularly in regions where unconventional gas production has yet to occur, or is in its infancy. Environmental concerns and policy constraints also have the potential to limit unconventional gas output, particularly in Europe. The future of unconventional gas production and the extent to which it is developed over the coming decades is heavily dependent on government and industry responses to environmental challenges, public acceptance, regulatory and fiscal regimes and widespread access to expertise, technology and water.

Shale gas projects have contributed significantly to increased gas production in the US over the past five years. There is an expectation that developments in the US may be copied in other regions around the world. Given that unconventional resources are more widely dispersed than conventional resources, patterns of future gas production and trade may change. This is because all major consuming regions have estimated recoverable gas resources that are much larger than what were estimated only five years ago.

Figure 2.3: Change in natural gas production by country (New Policies Scenario)



Source: IEA 2011a

Non-OECD production

Under the IEA's New Policies Scenario, over 90 per cent of the incremental increase in world gas production to 2035 is projected to come from non-OECD economies (IEA 2011a). Gas production in the non-OECD is projected to increase at an average annual rate of 2.3 per cent to reach 3.5 tcm by 2035. (IEA 2011a)

Incremental increases in gas production are projected to be greatest in non-OECD Europe/Eurasia with production from the Russian Federation projected to increase from 572 bcm in 2009 to 858 bcm in 2035. Gas production in Turkmenistan and Azerbaijan is also expected to be substantial, with improved access to large gas consuming regions, such as China and Europe. Turkmenistan already supplies gas to China through a pipeline that has been in operation since 2009. The pipeline which connects Turkmenistan to China via Kazakhstan and Uzbekistan was recently expanded to a capacity of 40 bcm a year. The possible opening of the southern gas corridor between the Caspian Sea and southern Europe could eventually allow Azerbaijan and other Caspian producers and Iraq to access European markets via pipeline.

Production in the Middle East is projected to increase at 2.5 per cent a year from 2009 to reach 773 bcm by 2035. Much of the growth has occurred in Qatar (in 2010 and 2011) as newly built LNG plants increase their throughput and the Pearl GTL project ramps up. Production is expected to increase from about 89 bcm in 2009 to more than 160 bcm in 2015, but then rise more slowly under the influence of the moratorium on new development projects which has been put in place pending the outcome of a study of the effects of current projects on the world's largest gas field, the North Field (IEA 2011a).

China is the only country with estimated shale gas resource greater than the US. China's gas production is projected to rise from 85 bcm in 2009 to 290 bcm in 2035, with the bulk of this increase expected to come from unconventional sources. While the IEA projects a substantial increase in China's shale gas production, it does not necessarily follow that it will be able to increase production as cheaply and easily as has occurred in the US (see Box 2). China's gas imports from the global market are, therefore, likely to continue to grow.

Box 2.2: Will China replicate the US shale gas experience?

US shale gas production more than tripled between 2007 and 2010, underpinned by a combination of relatively high gas prices and developments in horizontal drilling technology. The development of the shale gas industry has had a profound effect on the North American gas market. North America is currently only a small LNG importer, whereas five years ago it appeared likely that there would be a need for significant LNG imports before 2010. The expectation of significant imports resulted in the construction of a large amount of import infrastructure in the second half of the last decade. As a result of increased domestic supply, this import infrastructure is heavily underutilised. US gas prices have fallen rapidly, with increased domestic production. For instance, the key US marker, the Henry Hub price, fell from US\$12 per GJ in June 2008 to below US\$2 per GJ in April 2012.

While shale gas exploration in China is in its infancy, a number of preliminary studies have identified substantial resources. The development of the shale gas industry in China, however, faces challenges not present in the US. For example, US shale gas is generally located around 1500 to 3500 metres below the surface. By contrast, in China the shale is understood to be located further underground—generally at depths 3500 metres below the earth's surface. The shale geology in China is generally more challenging than in the US with more fracturing required to extract the latent gas. The carbon (or energy) content in China's shales is also understood to be around 1–5 per cent, whereas in the US it is, typically, around 5–10 per cent (PetroChina 2012).

The topography of the landscape affects the economics of shale gas production, as it alters the number of wells that need to be drilled and the cost of establishing a pipeline network. The most prospective areas for shale gas in China are in the province of Sichuan in central China, the Tarim Basin in the far west, and Inner Mongolia in the north.

The shale gas resources of Sichuan are located in the mountainous parts, but the region also has a long history of gas production. In the north and west of China, limited water is available, which is a critical input into the fracturing process.

By contrast, in the US, shale gas is located in areas of generally flat terrain, making drilling comparatively easy. There is also substantial infrastructure in place that, combined with an advanced market and regulatory structure that allows third party access to infrastructure, has enabled rapid increases in shale gas production to be marketed efficiently.

OECD production

Gas production in the OECD is projected to increase at an average rate of around 0.5 per cent a year to reach 1.3 tcm in 2035 (IEA 2011a), with increases in North America and Australia offsetting falls in Europe.

Over the last five years, gas production in the US has increased at an average annual rate of 4.5 per cent, well above the world average of 2.6 per cent (IEA 2011b). Increases in US production are largely a result of the exploitation of shale gas, which has put downward pressure on prices. In April 2012, Henry Hub gas prices traded below US\$2 per GJ, the lowest they had been in over a decade. The Henry Hub price has fallen consistently over the past four years underpinned by growth in shale gas production. Despite US gas prices being below US\$3 a

GJ over the past 12 months, there has been no decrease in production. Much of the shale gas currently being produced is in 'wet' shale plays where liquids are the primary target. This gas is essentially 'costless', because total production costs are far exceeded by oil revenues and it can be more costly to flare the gas than to give it away.

Gas production in North America is projected to increase at 0.6 per cent a year to total 932 bcm in 2035. The share of unconventional gas, as a proportion of total gas production, is projected to increase from 56 per cent in 2009 to 64 per cent in 2035 (IEA 2011a).

European gas production is projected to decline at an average rate of 1.4 per cent a year to total 204 bcm in 2035. Falls in gas production from the UK and the Netherlands are projected to offset increases in conventional gas production in Norway and projected expansion of unconventional gas production in Poland.

Box 2.3: Attitudes towards unconventional gas production in the OECD

In North America (Canada and the US, in particular) shale gas has been produced for a number of years. In many parts of North America, the industry enjoys community support because of the economic benefits (employment and lower energy prices) that shale gas brought to production regions. However, there are increasing concerns about the environmental impacts of shale gas production including possible contamination of water sources and the use of chemicals in hydraulic fracturing. As a result of these concerns, new rules have been introduced. For example, the US Environmental Protection Agency ruled in April 2012 on flaring and venting, and volatile organic compounds standards.

Vast shale gas resources are estimated throughout continental Europe, including in Denmark, Sweden, France, Germany, the Netherlands, Switzerland and Poland. At present, there is no large-scale production of shale gas in Europe and the production outlook is uncertain. Much of Europe's reserves are located in densely populated areas. This may create challenges associated with land access and community opposition. Unlike the US, land owners do not own the resources beneath their properties. As a result, they cannot reap the same financial benefits as a land owner in an equivalent position in the US. Local communities in Europe may also be more likely to object to gas extraction, particularly where there is no history of oil and gas production. Currently, the European Commission is undertaking various studies into the economics and environmental implications of shale gas production to assess the existing regulatory framework that governs unconventional gas production.

Trade

In 2011 international gas trade equated to 1025 bcm, or around 32 per cent of global consumption (BP 2012). Around a third of internationally traded gas was transported in the form of LNG, with the remainder transported via pipeline. Total LNG trade increased by 9 per cent in 2011, to 327 bcm (240 Mt) (IEA 2012). Global LNG trade is projected to reach 313 Mt (426 bcm) in 2017 (IEA 2012).

In 2011 around 695 bcm of gas was traded via pipeline, with around 68 per cent of the trade destined for Europe (including OECD and non-OECD Europe) (BP 2012). Around 40 per cent of

Europe's pipeline imports are sourced from the Russian Federation, with a further 20 per cent from Norway. North American pipeline trade was around 130 bcm in 2011. The vast majority of it was two-way trade between the US and Canada (BP 2012).

LNG-based gas trade has expanded rapidly over recent years, with global liquefaction capacity at the end of 2011 estimated at 279 Mt, up from 179Mt in 2001. Table 2.5 shows the top four LNG producing countries, all of which supply gas to the Asia-Pacific gas markets.

Table 2.5: Major LNG exporters, 2010

		Qatar	Indonesia	Malaysia	Australia	World
Proved gas reserves	tcm	25	3	4	3.8	208
– Share of world	%	12	1	1	2	
– Reserve to production ratio	years	>100	39	39	84	64
LNG Exports	Mt	76	22	25	19	245
– Share of world market	%	31	9	10	8	
– World ranking	no.	1	3	2	5	

Source: BP 2012

As a result of a geographical mismatch of locations with abundant gas resources and locations with rising demand, the volume of gas traded international is projected to increase (BREE 2012a). Imports of gas by all major importing regions, with the exception of the US, are expected to grow over the longer term, particularly in non-OECD regions (IEA 2011a). The pace of liquefaction capacity additions is slowing, but gas shipped as LNG is projected to account for 42 per cent of inter-regional gas trade by 2035.

Trade in Asia-Pacific

In 2011, LNG imports into the Asia-Pacific region accounted for 63 per cent of global trade. Asia-Pacific imports increased 19 per cent in 2011, relative to 2010, to total 151 Mt (IEA 2012). Japan was the largest LNG importer, followed by the Republic of Korea, China, Chinese Taipei and India.

Japan is completely reliant on LNG imports for its gas supply. In 2011, Japan's imports of LNG are estimated to have increased, with almost all the increase coming after May, so that in some months LNG shipments were up 20 per cent from the corresponding month a year earlier. In 2012, Japan is expected to increase its imports of gas for electricity generation to offset the loss of nuclear generation capacity that resulted from the March 2011 earthquakes and tsunami. As of May 2012, all nuclear plants have been shut down with a loss of some 280 terawatt hours of power output nationally.

Projections of Japan's LNG imports over the medium term are largely dependent on government policies that will dictate if, and when, nuclear capacity is restarted. Japan's LNG imports are projected to increase at an average annual rate of 2 per cent from 2014 to total

80 Mt in 2017 (BREE 2012a). Over the longer term, the planned closure of aging coal-fired electricity generation facilities is likely to sustain growth in gas consumption. However, assumed weaker economic growth, a declining population and an ageing workforce will constrain the rate of growth in gas consumption (EIA 2011a).

The Republic of Korea's gas supply consists entirely of LNG imports. In 2011, imports of LNG increased by an estimated 12 per cent to total 33 Mt, underpinned by a rise in gas use for electricity generation and growing consumption of residential and commercial gas. In 2012 and 2013, the Republic of Korea's LNG imports are forecast to increase by 7 per cent to total 38 Mt in 2013 (BREE 2012a). Increasing imports reflect an expectation that gas will continue to play a critical role in peak load electricity generation supported by the implementation of a policy to expand the gas distribution network. From 2014 to 2017, however, fewer proposed expansions of power generation facilities will moderate the growth in gas in the electricity sector. The successful completion of infrastructure expansions designed to increase residential and commercial access to gas, but without further investment potential growth in gas consumption will moderate over the medium to longer term. By 2017, imports of LNG into the Republic of Korea are projected to total 42 Mt (BREE 2012a).

In 2011, China imported an estimated 12.5 Mt of LNG. As consumption in China outpaces increases in domestic gas production, China is expected to become a much more important regional importer of gas. In 2012, China's LNG imports are forecast to increase 30 per cent to total 16 Mt supported by additional regasification capacity at the Zhejiang Ningbo and Dalian facilities. In 2013, LNG imports are forecast to grow by an additional 13 per cent to total 19 Mt. Increases in LNG imports are forecast to be supported by the expected commissioning of the Zhuhai Jinwan and Tangshan facilities.

Between 2014 and 2017, several additional LNG regasification terminals are scheduled to start up, underpinning China's LNG imports over the medium term. Combined, these projects are expected to support about 37 Mt of LNG imports into China by 2017.

Over the longer term, the IEA projects under its New Policy Scenario that China's import requirement, from pipeline and LNG, will grow from 10 bcm (equivalent to 7 Mt of LNG) in 2009 to 125 bcm (92 Mt LNG) in 2020 and 210 bcm (154 Mt) in 2035 (IEA 2011a). However, a significant risk to this projection is a possible moderation of China's overall rate of economic growth and/or greater than projected development of its own unconventional gas resources.

India's gas consumption is projected to increase over the medium term, primarily due to increased gas consumption in its electricity and industrial sectors. Greater gas consumption will need to be met by increases in domestic production and imports. While India is expanding pipeline capacity over the medium term, LNG imports are forecast to supplement supply in the short term. In 2012, LNG imports into India are forecast to increase, supported by growth in India's regasification capacity (BREE 2012a).

Between 2013 and 2017, imports of LNG into India are projected to increase at an average annual rate of 5 per cent to reach 16 Mt in 2017. Over the medium term, growth rates of India's LNG imports are projected to ease as additional pipeline capacity is constructed (BREE 2012a).

Over the longer term, India's gas consumption is projected to increase at an average annual rate of 4.5 per cent, while domestic production is projected to increase by an average of 3.7 per cent a year to 2035. By 2035, India's net import requirements are forecast to be 66 bcm (49 Mt LNG) (IEA 2011a).

Imports of LNG into Chinese Taipei were around 12 Mt in 2011 (BP 2012). Demand for LNG in Chinese Taipei is projected to increase over the medium term, as a result of a change to the government's energy policy announced in November 2011. In particular, the commissioning of the 2700 MW Lungmen nuclear plant has been delayed until 2014 to allow more time to conduct strict safety checks. In the meantime, gas-fired electricity generation capacity is assumed to operate at a higher utilisation rate to meet increasing electricity demand (BREE 2012a).

From 2013, Chinese Taipei will be entitled to an additional 1.5 Mt a year from Qatar under contract, reducing spot market demand. Between 2014 and 2017, additional demand for gas could be supported by the closure of nuclear electricity generating capacity and its substitution with gas-fired capacity. During this period, LNG imports into Chinese Taipei are projected to increase 6 per cent a year to reach 17 Mt in 2017 (BREE 2012a).

While the IEA does not publish long-term projections of the consumption and production of gas in Chinese Taipei to 2035, it is likely that its net import requirement will continue increasing at a robust rate. A substantial proportion of these imports are likely to remain in the form of LNG.

Trade in North America

Despite being the world's largest producer of gas, the US has been traditionally a net importer of gas. Imports of LNG by the US peaked at 16 Mt in 2007, and totalled 7 Mt in 2011 (BP 2012). These relatively small LNG import volumes reflect minimum inputs required to keep LNG terminals operational and to meet contractual obligations. Recent declines in growth in LNG imports are due to rapid expansions in US domestic unconventional (mostly shale) gas production. However, the US still remains a net importer of gas (mostly via pipeline from Canada and Mexico), with net imports amounting to 98 bcm (73 Mt LNG) (BP 2012).

The production of unconventional gas in the US has increased the domestic supply of gas, and put strong downward pressure on local gas prices in recent years. In 2008 the Henry Hub gas price averaged US\$8.4 a GJ (peaking at US\$12.6 a GJ in mid 2008) and decreased to average US\$3.8 a GJ in 2011. By April 2012, the Henry Hub gas price has fallen below US\$2 a GJ.

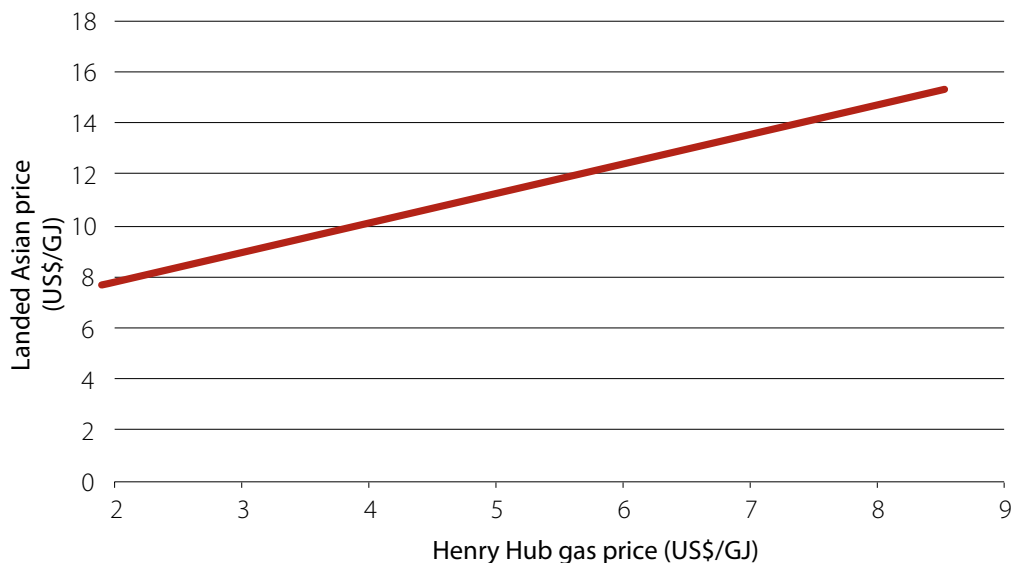
The growing disparity between US gas prices and prices in European and Asian markets, combined with plans to widen the Panama Canal, have increased the attractiveness of investment opportunities in the US to re-export imported LNG, and to export domestically produced shale gas. The potential exports of shale gas LNG from the US could place downward pressure on Asian LNG prices. To date, several companies have received federal government approval to re-export LNG.

As of February 2012, nine project proponents had applied to the US Department of Energy (DOE) to export a combined quantity of 104 Mt of domestically produced LNG a year (Table 2.6). The only project to have obtained approval to export to both free trade agreement (FTA) and non-FTA countries is Cheniere Energy's Sabine Pass terminal. Cheniere Energy has been approved to build a liquefaction facility with an export capacity to export 16 Mt of LNG per year to FTA and non-FTA nations. Over 90 per cent of the LNG from Sabine pass has been sold under long term contracts to buyers in the Republic of Korea, Japanese, Indian and European buyers. The LNG export terminal will be based on some of the existing infrastructure associated with the regassification terminal such as the storage tanks, jetties and other infrastructure.

Canada appears set to become an LNG exporter in the short to medium term. The 5 Mt Kitimat project, which has an annual capacity of 5 Mt (7 bcm) and is located in British Columbia, is at an advanced stage of planning with a final investment decision scheduled in the near future. A number of other projects are also proposed for British Columbia that could be in operation by the end of this decade. For some of the projects, gas will be sourced from fields located around the Rocky Mountains. There is also the potential for Canadian liquefaction facilities to source gas from the US, particularly if regulators in the US limit LNG exports to non-FTA countries.

LNG exporters in the US are not vertically integrated, as they are in Australia. Instead, US liquefaction companies purchase gas from domestic producers at a price similar to the Henry Hub price. To reduce their price risk, these companies negotiate contracts linked to the Henry Hub price plus a fixed cost associated with liquefaction and shipping. Based on Cheniere Energy's contract terms, at a Henry Hub price of US\$2 per GJ (the average Henry Hub price in April 2012), LNG from the US could be delivered into north Asia at a price of around US\$8 per GJ. This compares with the average Japanese LNG import price in February 2012 of around US\$15 per GJ. Figure 2.4 shows the possible relationship between the Henry Hub price and a landed northern Asia LNG price.

Figure 2.4: US LNG export prices to Asia



Source: BREE

An important element in the future pricing of LNG exports from North America is the transport route to North Asia. The pricing relationship in Figure 2.4 is based on shipping costs associated with LNG carriers travelling around South Africa. However, the Panama Canal is currently being expanded to handle larger vessels and from 2014 this will allow LNG carriers to pass through the canal. A route via the Panama Canal is understood to reduce shipping costs from North America to Asia by around \$0.75/GJ.

Table 2.6: Applications received by DOE to export US produced LNG, as of early May 2012

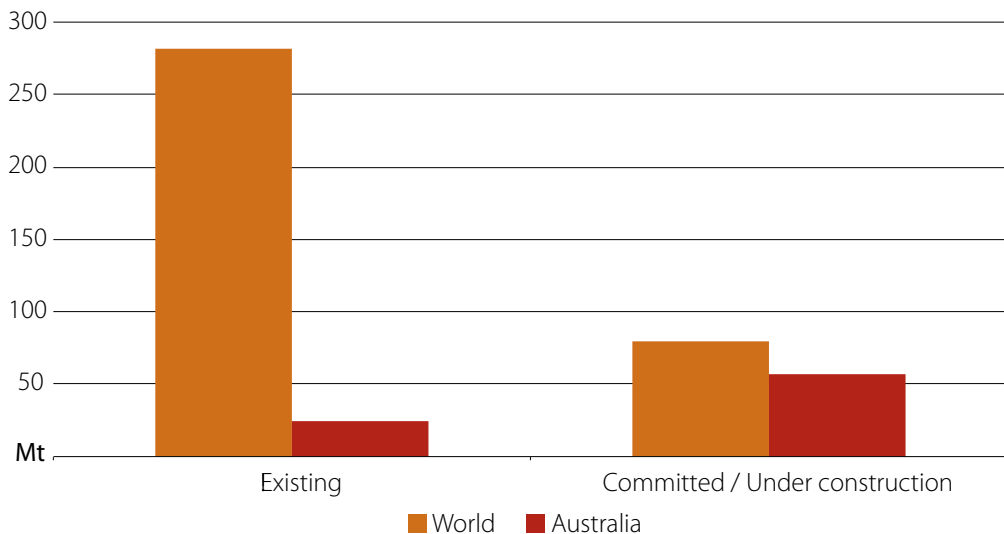
Project	Quantity (Mt a year)	Exports to FTA countries	Exports to non-FTA countries
Sabine Pass Liquefaction	16	Approved	Approved
Freeport LNG Expansion	21	Approved	Under DOE Review
Lake Charles Exports	15	Approved	Under DOE Review
Carib Energy	<1	Approved	Under DOE Review
Dominion Cove Point LNG	8	Approved	Under DOE Review
Jordan Cove Energy Project	9	Approved	Under DOE Review
Cameron LNG	13	Approved	Under DOE Review
Gulf Coast LNG Export	21	Under DOE Review	Under DOE Review
Cambridge Energy	2	Under DOE Review	na
Total	106		

Source: US Department of Energy, IEA 2012

Australian trade

In 2011, Australia's LNG exports were 19 Mt and accounted for 8 per cent of global LNG exports. Although construction costs are relatively higher in Australia compared with other regions, Australia's proximity to Asian markets and low sovereign risks have, to date, proved more important in firms' investment decisions. At present around two thirds of total world LNG liquefaction capacity currently under construction is located in Australia (Figure 2.5). As a result of these investments, Australia's share of world LNG exports is projected to increase substantially over the next two decades. Australia is projected to become the world's second largest exporter of LNG, behind Qatar, as soon as 2015.

Figure 2.5: Australian and world LNG export capacity



Geographically, Australia is well placed to continue to supply the large existing markets of Japan and the Republic of Korea as well as the growing Chinese market. Located in the northern parts of Australia, LNG facilities are about one week shipping time away from north-east Asia. The benefit of the shorter distance, relative to exporters located in the Middle East or in the Atlantic Basin, is that it reduces the shipping time and costs associated with fuel and crew costs, and also requires fewer tankers.

The principal challenges for Australia's LNG export sector is that projects have relatively high costs, slower construction times and larger capital expenditure. To some extent, this is due to the remote locations of offshore gas reserves in Australia, and the general global increases in oil and gas capital costs in the last few years. For example, the Gorgon and Wheatstone projects have a capital cost of around \$3 billion per million tonne of annual capacity, while the Ichthys project has a cost of around \$4 billion per million tonne of annual capacity. These costs are the highest in the world and are attributed to high labour and other input costs and a high Australian dollar. The average cost of production from these projects, however, should decrease if additional trains are added as is planned at Gorgon, Pluto and Wheatstone. By

comparison, the PNG LNG project in Papua New Guinea has a capital cost of US\$2.3 billion per million tonne of annual capacity, while the soon to be completed Angola LNG project in southern Africa had a cost of below US\$1.7 billion per million tonnes of annual capacity.

Counterbalancing these relatively higher costs are Australia's stable system of government, high levels of personal security, well-defined property rights, and established fiscal and regulatory frameworks that encourage foreign investment. These factors provide projects in Australia with a lower level of sovereign risk relative to competing projects in Western and Northern Africa, Latin America, Iran and the Russian Federation.

3. The Australian gas markets

Australia has three distinct geographically and economically separate gas markets: the Eastern gas market, Western gas market and Northern gas market. The separation of these markets reflects the distance between the main consumption centres. This spatial separation also represents the geographical location of gas reserves that underpin supply into these markets.

Reserves and resources

As at January 2011, Australia's conventional gas economic demonstrated resources (EDR) were estimated to be 2.92 tcm (see Table 3.1) (GA and BREE 2012). Australia's CSG EDR are estimated to be 0.93 tcm (GA and BREE 2012). Australia's total EDR account for nearly 2 per cent of global EDR.

Table 3.1: Australia's gas resources

Resource Category	Conventional Gas		Coal Seam Gas		Tight Gas		Shale Gas		Total Gas	
	PJ	tcm	PJ	tcm	PJ	tcm	PJ	tcm	PJ	tcm
EDR	113,400	2.92	35,905	0.93	-	-	-	-	149,305	3.85
SDR	59,600	1.54	65,529	1.69	-	-	2,200	0.06	127,329	3.28
Inferred	~11000	0.28	122,020	3.14	22052	0.57	-	-	155,072	4.00
All identified resources	184,000	4.74	223,454	5.76	22052	0.57	2,200	0.06	431,706	11.13
Potential in ground resource	unknown	unknown	258,888	6.67	unknown	unknown	435,600	11.23	694,488	17.90
Resources – identified, potential and undiscovered	184,000	4.74	258,888	6.67	22052	0.57	435,600	11.23	900,540	23.21

Note: Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012.

CSG 2P reserves and 2C resources are used as proxies for EDR and SDR respectively.

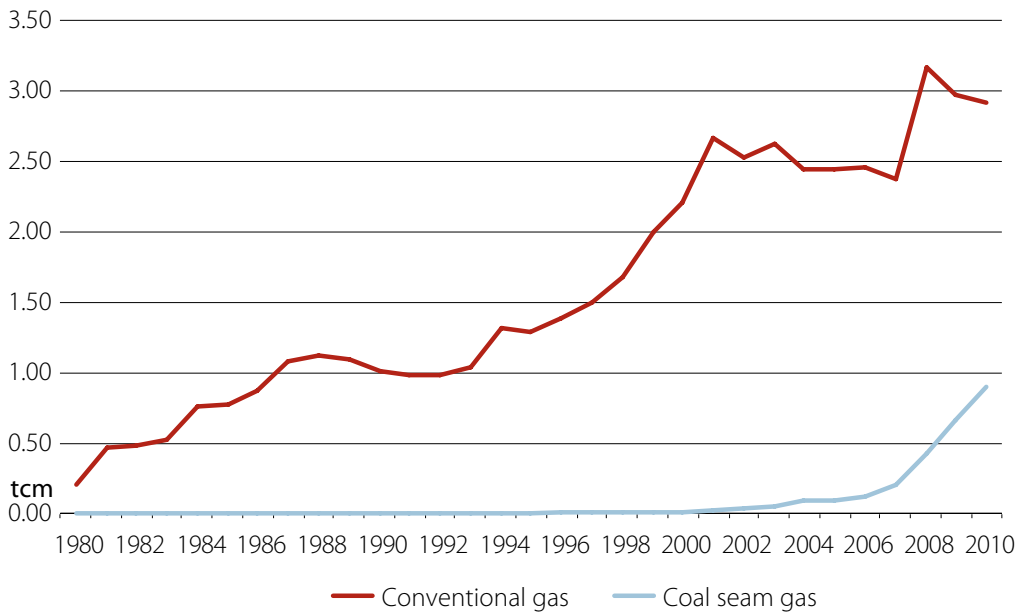
Sources: GA and BREE 2012

At the beginning of 2011 there were no EDR of shale gas or tight gas. However, Geoscience Australia (GA) estimates that, as of 2011, Australia's tight gas resources are around 22 052 PJ (0.57 tcm), and that Australia's shale gas resources are around 435 600 PJ (11.23 tcm). Thus, Australia's shale gas resources are nearly twice as large as its CSG resources.

Both shale gas and tight gas resources are in very early stages of development. Prospective areas for shale gas explorations and development include the Cooper Basin that is a region that already has existing gas infrastructure. The eastern parts of the Northern Territory also exhibit potential, however, in this region there is limited established infrastructure. While the distance of shale gas fields from infrastructure and markets poses challenges, their remoteness is advantageous because they are not near located near contentious populated areas. This could reduce the land access and competition issues that are affecting CSG developments. While shale gas exploration is still at an early stage, it could become a significant source of supply over the longer term.

Between 1980 and 2010, Australia's EDR of conventional gas have increased at an average rate of 9 per cent a year. Australia's EDR of CSG were negligible until the early 2000s. Between 2000 and 2010, Australia's EDR of CSG increased at an average annual rate of 56 per cent (see Figure 3.1).

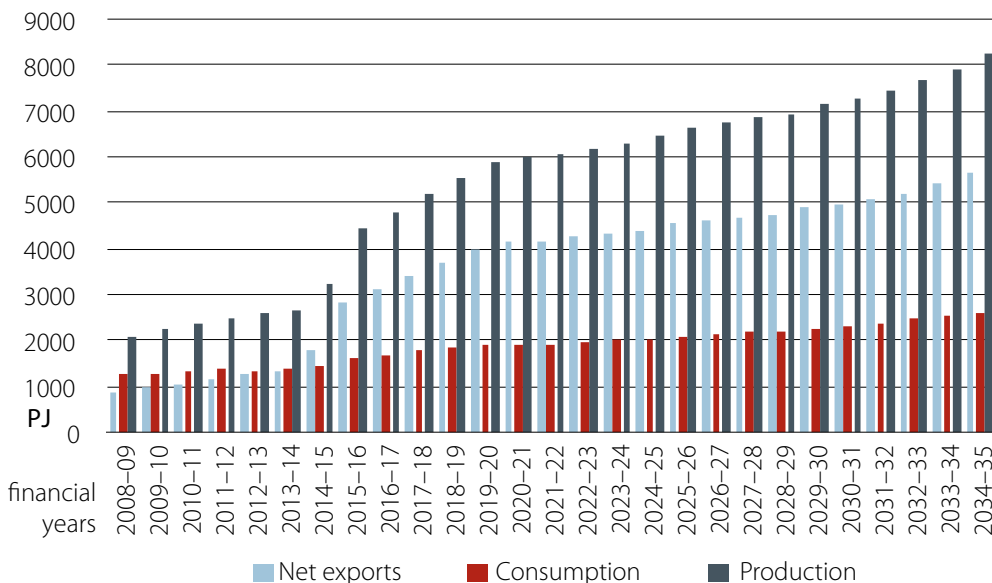
Figure 3.1: Australia's EDR of gas



Source: Geoscience Australia

Australia's gas production, consumption and exports are all projected to grow significantly over the period to 2034–35 (see Figure 3.2). Growth in consumption is expected to be underpinned by growing gas-fired electricity generation and increased consumption in the mining sector (including gas consumed in the process of producing LNG).

Figure 3.2: Australia's gas balance to 2034-35



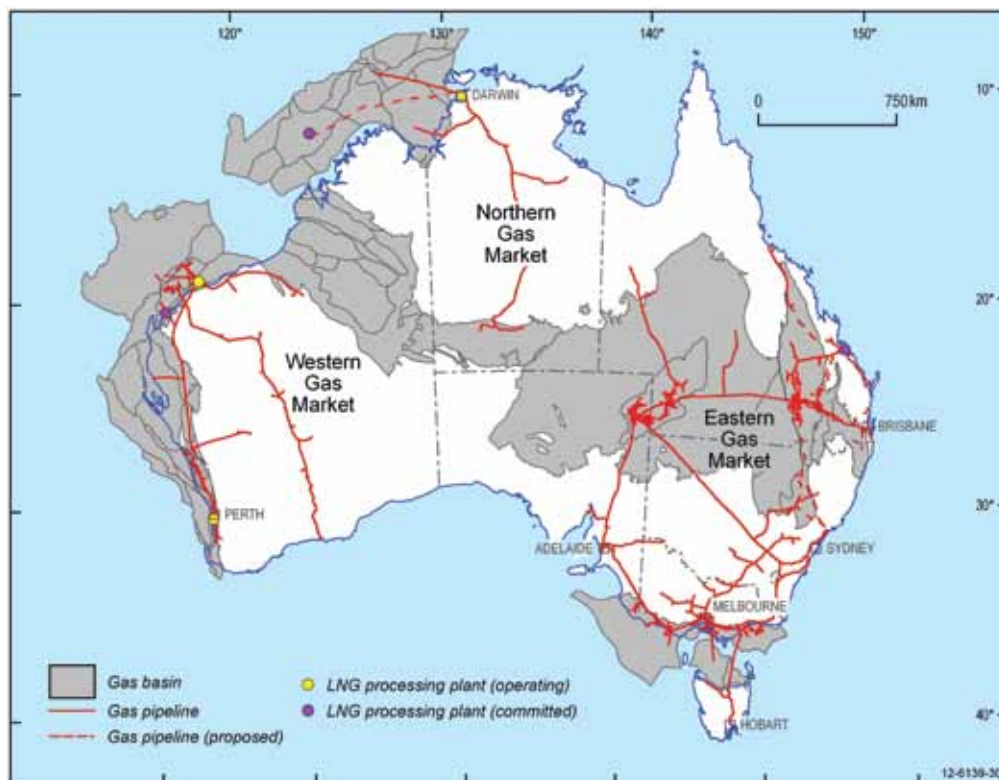
Source: BREE 2011a

Australia's gas infrastructure network

High pressure transmission pipelines transport gas over long distances to domestic markets and LNG terminals for export. A network of distribution pipelines delivers gas from points along transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the gas leaving a transmission system for billing and gas balancing purposes, and reduce the pressure of the gas before it enters a distribution network (AER 2011).

Over the past decade, Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT have become interconnected following the construction and expansion of new and existing pipeline facilities and networks. The interconnection across the eastern states of Australia has increased security of supply and improved the competitiveness of the gas market for producers, infrastructure operators and consumers. Because of their geographical distance, Western Australia and the Northern Territory remain separated from other markets.

Figure 3.3: Australian gas basins and transmission pipelines



Source: GA

A gas distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a ‘backbone’ that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers (AER 2011).

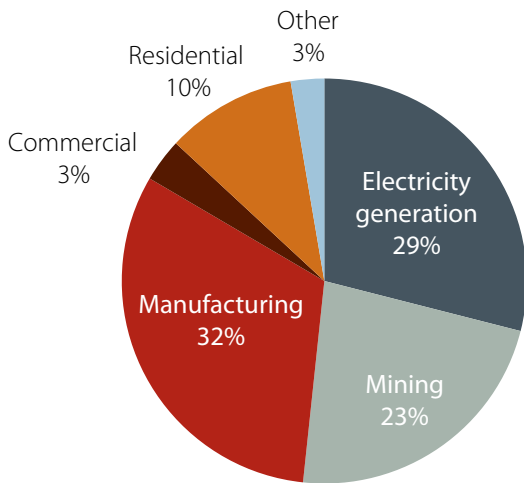
Consumption

Australia’s gas consumption was 36 bcm in 2009–10, and has increased by 6 per cent a year over the past 5 years, and 4 per cent a year over the past 10 years (ABARES 2011). The growth in gas consumption over this period reflects an increase in LNG production, gas-fired electricity generation, and consumption for industrial purposes.

Gas accounted for 23 per cent of total primary energy consumption in Australia in 2009–10. The manufacturing, electricity generation, mining and residential sectors are the major consumers of gas (see Figure 3.4). The manufacturing sector is the largest consumer of gas and is comprised of a few large consumers, including metal product industries (mainly smelting and refining activities), the chemical industry (fertilisers and plastics), and the cement industry.

The share of gas-fired electricity generation has increased in recent years and accounted for an estimated 15 per cent of electricity generation in 2009–10 (BREE 2012b). The manufacturing sector is Australia’s largest consumer of natural gas, followed by the electricity generation, and mining sectors. The mining sector consumes a large amount of natural gas in the process of producing LNG. This is largely due to gas being used as an energy source in the liquefaction process. Around 10 per cent of gas that enters an LNG plant is consumed in the process of liquefaction and pressurisation of the gas. The residential sector is characterised by a large number of small demand consumers. The major residential uses of gas include water heating, space heating and cooking.

Figure 3.4: Australian primary consumption of gas by sector in 2009–10

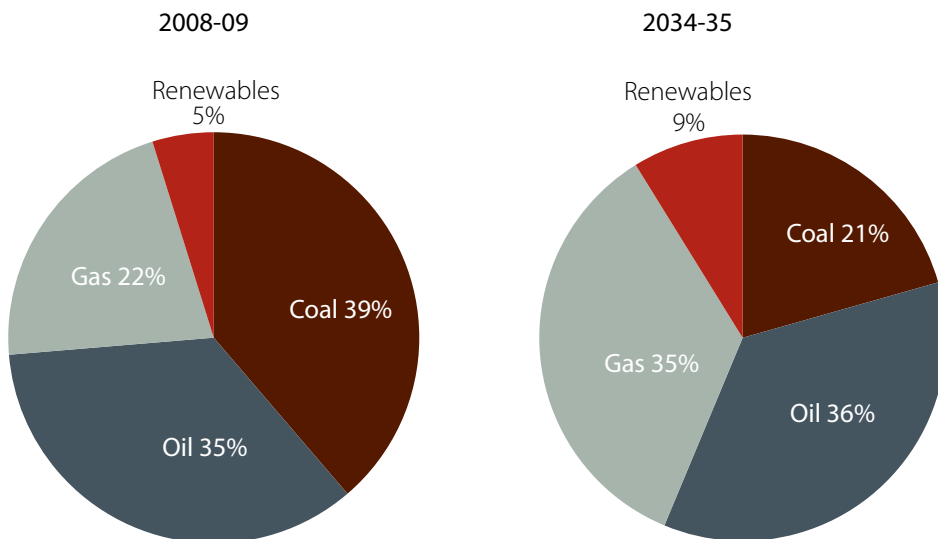


Source: BREE Australian Energy Statistics database

As indicated in Figure 3.2, Australia’s domestic gas consumption is projected to increase by 3 per cent a year between 2009–10 and 2034–35, more than doubling to 67 bcm by 2034–35 (BREE 2011a). This expected growth is driven primarily by the electricity generation sector and the mining sector (primarily associated with the consumption of gas in LNG production).

In terms of total primary energy consumption, gas is expected to increase its share of total primary energy consumption to 35 per cent in 2034–35 compared with its share of 22 per cent in 2008–09. The share of gas-fired electricity generation, as a proportion of total electricity generation, is projected to increase from 16 per cent in 2008–09 to 36 per cent in 2034–35 (see Figure 3.5).

Figure 3.5: Total primary energy supply: 2008–09 and 2034–35



Source: BREE 2011a

The shift towards gas-fired electricity is underway with a number of gas-fired power stations constructed and brought into operation over the past three years (see Table 3.3). This trend is expected to continue with a further seven gas-fired power station projects under construction that, in total, are equivalent to 2 per cent of Australia’s electricity generation capacity (BREE 2011b). Over the long term, the share of gas-fired electricity relative to total electricity is expected to increase under the assumption that at least some of the 42 gas-fired electricity generation projects currently in a planning stage are brought into operation.

Table 3.3: Completed CSG/gas-fired electricity generation projects since October 2008

Fuel	Project	Company	Location	Capacity (MW)
CSG	Darling Downs	Origin Energy	QLD	630
CSG	Condamine	BG Group/ANZ Infrastructure Services	QLD	140
CSG	Braemar 2	ERM Power/Arrow Energy	QLD	450
Gas	Kwinana Swift	Perth Energy	WA	120
Gas	Colongra	Delta Electricity	NSW	660
Gas	Neerabup	ANZ Infrastructure Services/ERM Power	WA	320
Gas	Tamar Valley	Aurora Energy	TAS	390
Gas	NewGenKwinana	Babcock and Brown Power/ERM	WA	330
Gas	Newman	Babcock and Brown Power	WA	37
Gas	Quarantine Expansion	Origin Energy	SA	120
Gas	Tallawara (Stage 1)	TRUenergy Tallawara	NSW	400
Gas	Uranquinty	Origin Energy	NSW	640
Gas	Weddell (Stage 2)	Power and Water Corporation	NT	43

Source: BREE 2011b

Production

Australia's gas production has increased steadily over the past 20 years from 21 bcm in 1990–1991 to 53 bcm in 2010–11, inclusive of gas feedstock into LNG facilities. The increase in production has been underpinned by a steady increase in domestic demand and growth of gas exports.

Domestic production of gas, excluding gas feedstock into LNG facilities, totalled 28bcm in 2010–11, with the majority of production located in either the Carnarvon Basin (Western market), Gippsland Basin (Eastern market) or Surat-Bowen Basin (Eastern market). Details of the production by field are provided in Table 3.4.

Table 3.4: Australian gas production by field in 2010–11 a

Basin	State or nearest state	Field	Production (million cubic meters)
Amadeus	NT/WA		41
Bass Strait	VIC/TAS		619
Bonaparte	WA/NT		508
Carnarvon	WA	Blacktip	508
		NWS	8,871
		Other	5,404
Cooper JV	QLD/SA		3,467
Gippsland	VIC		2,604
		Gippsland JV	6,500
		Longtom	6,121
Narrabri	NSW		380
Otway	SA/VIC		12
		Casino	2,721
		Katnook	852
		Minerva	47
		Thylacine	604
Perth	WA		1,219
Surat-Bowen	QLD/NSW		91
		Berwyndale	6,040
		South1	1,381
		Daandine	314
		Fairview	1,089
		Kogan North	87
		Meridian	82
		Seamgas	
		Moranbah	363
		Mungi	21
		Peat	81
		Scotia	255
		Spring Gully	1,172
Talinga	650		
Tipton West	303		
Sydney	NSW		146
Grand Total			28,156

a excludes gas feedstock into LNG facilities

Source: Energy Quest

Strong growth in domestic and global demand for gas is expected to underpin the development of new gas fields and LNG capacity in Australia. Gas production is projected to grow at an average annual rate of 5.5 per cent a year to 213 bcm in 2034–35 (BREE 2011a). Projected growth in gas production in all three of Australia’s gas markets will be supported by new export capacity.

Exports

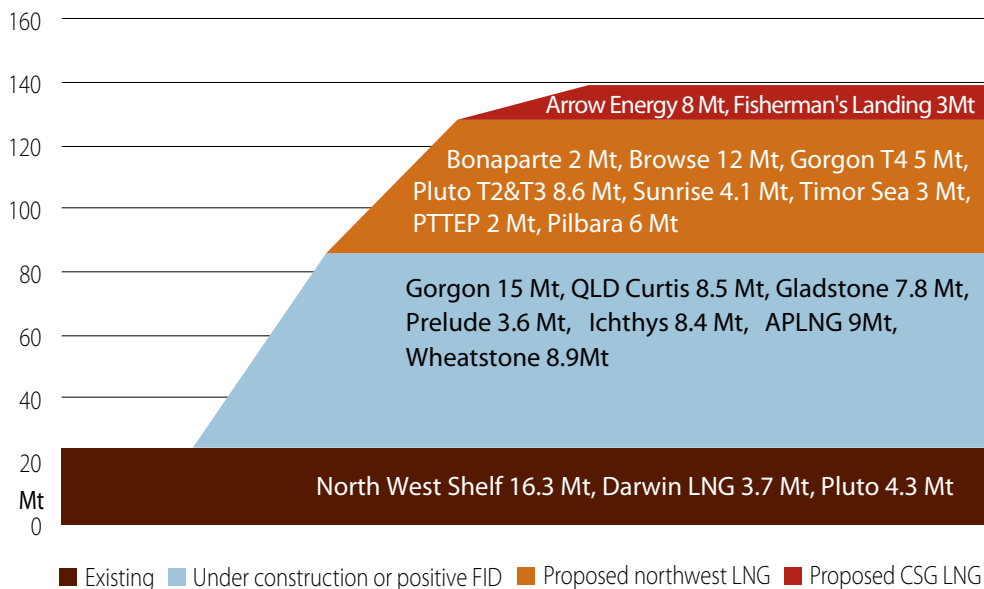
In 2010–11, Australia’s LNG exports were around 20 Mt and accounted for about 50 per cent of Australia’s gas production. Exports of LNG have increased strongly in recent years—by around 11 per cent a year over the past five years—supported by expansions to the North West Shelf (NWS) project and the start up of the Darwin LNG project. In 2010, around 70 per cent of Australia’s LNG exports were sold to Japan. Australia’s second largest market is China, which accounted for a further 20 per cent (BP 2011).

There are currently three export-operational LNG projects in Australia—the NWS Project, the Darwin LNG project and the Pluto project—representing 24.2 Mt of LNG export capacity. Based on projects that are at an advanced stage of development, that is projects that are either committed or under construction, Australia’s LNG exports are projected to increase to over 63 Mt annually by 2016–17.¹

Beyond these projects, there are a number of other LNG projects under consideration which, if brought into operation, could increase Australia’s LNG capacity to over 100 Mt and could make Australia the world’s largest LNG exporter by the end of the decade (see Figure 3.6). Further details on these projects can be found in the Annex.

1 Assuming a positive FID on the second train of APLNG by mid 2012

Figure 3.6: Overview of Australia's LNG production capacity



Note: assumes a positive FID on the second train of the APLNG facility by mid 2012

Source: BREE 2012c

Market structure

Variations in market fundamentals between the Western market, Eastern market and Northern market, such as the size and location of gas resources, the demand profile and exposure to international markets makes for noticeable price differentials between markets, and even within each market.

Western market

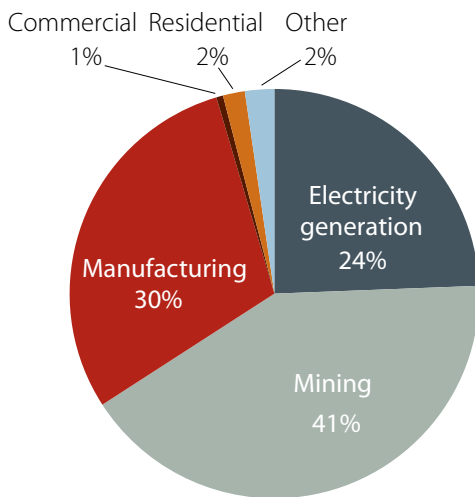
The Western market is a large, self-contained market. Existing upstream gas supply infrastructure is at or near production capacity (RET 2011). However, capacity constraints should moderate as a result of a ramp-up of production from the Devil Creek facility, which commenced operations in late 2011. This facility is the state's third gas processing facility and is expected to increase Western market gas supply by up to 20 per cent.

The largest pipeline in the Western market, in terms of capacity, is the Dampier Bunbury pipeline which connects the gas fields in the north of Western Australia to the large consuming centres in the south. The Goldfields pipeline connects the gas fields in northern Western Australia to mines in the Pilbara, and then travels south to the mining regions around Kalgoorlie.

The Goldfields pipeline is currently being expanded by around 44 TJ (1.1 mmcm) per day following commitments by Rio Tinto and BHP Billiton to purchase additional gas supplies to support increasing iron ore production. The pipeline’s operator, Australian Pipeline Group, has agreed to expand the pipeline’s capacity by 28 per cent to 73 PJ (1880 mmcm) a year at a capital cost of \$150 million. The pipeline expansion is scheduled to be completed in 2013. Rio Tinto has contracted to transport through the pipeline an additional 7.3 PJ (188 mmcm) a year for 20 years, while BHP Billiton has contracted for 8.7 PJ (224 mmcm) a year for 15 years. Both BHP Billiton and Rio Tinto will use the increased gas supplies to support expansions at their iron ore operations in the Pilbara.

Domestic gas consumption in the Western market in 2009–10 was 15 bcm and accounted for around 40 per cent of Australia’s gas consumption. Gas consumption in the Western market has increased by nearly 6 per cent a year over the past decade, underpinned by strong demand from the mining sector, industrial activity and gas exports. The mining sector is the largest consumer of gas in the Western market, followed by the manufacturing sector and electricity generation sector (see Figure 3.8).

Figure 3.8: Western market primary consumption of gas by sector in 2009–10



Source: BREE Australian Energy Statistics database

In production terms, the largest Australian gas market is the Western market—accounting for nearly two thirds of Australian production in 2010–11. All of the gas produced in the Western market is from conventional sources with the vast majority sourced offshore. In particular, the Carnarvon Basin accounts for the majority of gas production in the Western market as it hosts gas fields that supply the NWS project. The NWS project has an LNG production capacity of 16.3 Mt or 22 bcm a year, and a domestic gas plant capacity of around 5.7 bcm a year. The other major sources of gas production in the Western market are fields associated with the Varanus Island and Reindeer gas plants.

Increased future gas production will be sourced from a number of new gas fields including Macedon and Spar. These three projects will sell their natural gas into the domestic market and followed changes in gas quality requirements by the Western Australia government. The current development of a number of new fields off the Western Australian coast will underpin LNG exports over the medium term. These fields include those associated with Pluto/Xena, Gorgon/lo/Jansz and Wheatstone/lago. Over the longer term, gas production in the Western market is projected to increase by 5.5 per cent a year to reach 123 bcm in 2034–35 (BREE 2011a).

The vast majority of Australia's LNG exports currently come from the Western market. Until April 2012, all of this was sourced from the NWS Project. This project has a capacity of around 16.3 Mt and accounted for around 81 per cent of Australia's LNG exports in 2010–11. Gas was first exported from the NWS project in 1989, when the project had a capacity of 5 Mt a year (two trains). Subsequent trains were added in 1992 (2.5 Mt), 2004 (4.4 Mt) and 2008 (4.4 Mt). At the end of April 2012, production commenced at the Pluto LNG facility (capacity of 4.3 Mt a year).

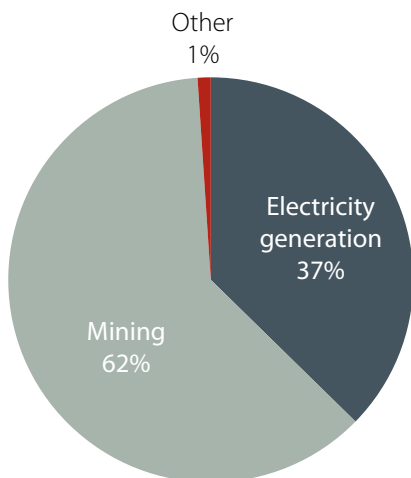
As of May 2012, there are four LNG projects under construction in the Western market, which have a total capacity of 36 Mt (see Table A1). These projects include: Gorgon (15 Mt a year; Chevron, Shell, ExxonMobil), Wheatstone (8.9 Mt a year; Chevron, Apache, Kufpek, Shell), Prelude (3.6 Mt a year; Shell, Inpex) and Ichthys (8.4 Mt a year; Inpex, Total) that will be piped 900 kilometres to Darwin for liquefaction. The Prelude LNG project will be the world's first floating LNG project that will allow gas to be processed above the field instead of the traditional method which is to process the gas at a land-based facility.

Northern market

Gas transmission infrastructure in the Northern market consists of two major pipelines. Historically, Darwin's gas supply was produced in the Amadeus Basin (in the south west of the Northern Territory) and transported via the Amadeus Basin to Darwin Pipeline. In 2009, a pipeline was built to deliver gas from the offshore Blacktip field in the Bonaparte Basin to the Amadeus Basin-Darwin pipeline. The new pipeline links gas processing plant at Wadeye (on the Northern Territory coast) to the Amadeus Basin-Darwin pipeline. Gas for the Darwin LNG plant is supplied via a dedicated pipeline from the Bayu Undan gas field 500 kilometres west of Darwin.

The Northern market is the smallest consumer of gas in Australia, accounting for 3 per cent of Australia's total gas consumption. A large proportion of consumption occurs at the Darwin LNG plant, where gas is consumed to produce LNG.

Figure 3.9: Northern market primary consumption of gas by sector in 2009–10



Source: BREE Australian Energy Statistics database

The Northern market is the smallest producer accounting for around 2 per cent of Australian production in 2010–11. Gas production in the Northern market was historically sourced from the onshore Amadeus Basin in the south of the Northern Territory. In 2009, the offshore Blacktip gas field, in the Bonaparte Basin, started production with gas piped onshore to supplement the declining Amadeus Basin supply. Over the long term, gas production in the Northern market is projected to increase at an average annual rate of 6.5 per cent to reach 26 bcm in 2034–35 (BREE 2011a).

In 2006, Australia’s second LNG facility, the Darwin LNG project, commenced operation. Gas supply to the Darwin LNG project is sourced via imports from the Joint Petroleum Development Area (Bayu Undan field) in the Timor Sea. Production from the Darwin LNG plant in 2010–11 was around 3.8 Mt or about one fifth of Australia’s LNG exports.

Eastern market

There are around 16 different producers operating across the Cooper, Gippsland, Otway and Surat-Bowen basins, serving eight major demand centres that are linked by an interconnected set of pipelines (see Figure 3.3).

CSG accounts for around one third of production in the Eastern market, with the balance coming from the Cooper Basin and offshore Victorian basins. Rising CSG production in Queensland and improved pipeline interconnection among the eastern states have enhanced the flexibility of the market to respond to customer demand. CSG production in Queensland and New South Wales rose by 17 per cent in 2010–11. New transmission pipelines, such as the QSN Link, provide the physical capacity to transport the gas to southern markets (AER 2011).

As Queensland's CSG production makes up an increasing proportion of total production in the Eastern market, there has been increased investment in transmission pipelines to enable gas delivery from Queensland to LNG terminals at Gladstone and to the southern states. Table 3.5 lists the major gas transmission pipeline investments since 2010 that have a total estimated cost of over \$3.8 billion.

Table 3.5: Major gas transmission pipeline investment since 2010

Pipeline	Owner/proponent	Scale	Cost (\$m)	Completion date
COMPLETED				
Queensland Gas Pipeline expansion	Jemena	Expansion from 79 TJ/d to 140 TJ/d	112	2010
Eastern Gas Pipeline	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
Victorian Transmission System (GasNet)	APA Group	Northern section expansion		2011
Moomba to Sydney Pipeline	APA Group	Young to Wagga lateral		2010
UNDER CONSTRUCTION				
South West Queensland Pipeline—stage 3	Epic Energy	Expansion—additional 199 TJ/d	760	2012
QSN Link—stage 3	Epic Energy			
Queensland Curtis LNG (QCLNG) Pipeline	BG Group	540 km		
Roma to Brisbane	APA Group	10 per cent capacity expansion	50	2012
Moomba to Sydney Pipeline	APA Group	Five year 20 per cent capacity expansion	100	2009–13
Victorian Transmission System (GasNet)	APA Group	Sunbury looping project		2012
ANNOUNCED				
Queensland Hunter Pipeline (Wallumbilla to Newcastle)	Hunter Gas Pipeline	831 km	900	
Gladstone LNG (GLNG) Pipeline	Santos, Petronas, Total, Kogas	420 km		2015
Arrow Bowen Pipeline (Bowen Basin–Gladstone)	Arrow (Shell and PetroChina)	600 km	1000	
Australian Pacific LNG (APLNG) Pipeline	Origin, Sinopec, ConocoPhillips	450 km		2014
Arrow Surat Pipeline	Arrow	450 km	550	
Young to Wellington Pipeline	ERM Power	219 km	200	
Lions Way Pipeline (Casino to Ipswich)	Metgasco	145 km	120	

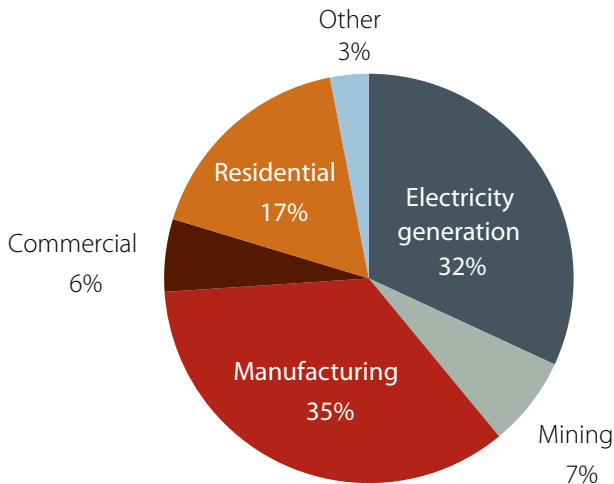
Source: AER 2011

There are opportunities to augment the gas transmission system to allow gas to flow from new gas processing facilities in the Bowen-Surat and Gunnedah basins to the major demand centres in New South Wales, Victoria, and South Australia (AEMO 2011). There is also the prospect of increased gas flows from the Bass Strait and Otway Basins to New South Wales via an expansion to the Eastern Gas Pipeline.

The total length of gas distribution networks in the southern and eastern jurisdictions was around 73 000 kilometres in 2011. These networks have a combined value of over \$7 billion. Investment to augment and expand the networks is forecast at around \$2.7 billion in the current access arrangement period (AER 2011).

In 2009–10, gas consumption in the Eastern market was around 20 bcm, and accounted for over half of Australia’s consumption. Gas consumption in the Eastern market has increased by an average of 3 per cent a year between 1999–00 and 2009–10 and is underpinned by increased consumption in the electricity generation sector. Increases in gas consumption in the Eastern market’s electricity generation sector, in part, reflect Queensland’s 15 per cent gas-fired electricity generation target that is due to end on 1 July 2012. The relatively slower rate of gas consumption growth, compared to the Western market, is due to the absence of an LNG industry and relatively weaker economic growth over the past decade. The manufacturing sector is the largest consumer of natural gas in the Eastern market, followed closely by the electricity generation sector (see Figure 3.10).

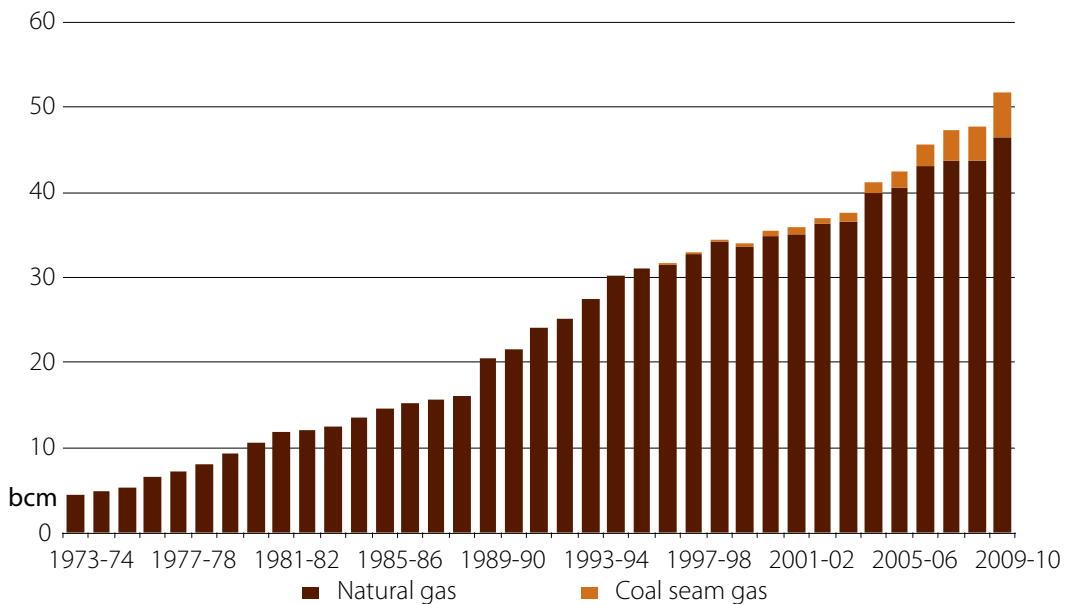
Figure 3.10: Eastern market primary consumption of gas by sector in 2009–10



Source: BREE Australian Energy Statistics database

The Eastern market accounted around 35 per cent of Australian gas production in 2010–11. Around two-thirds of gas production in the Eastern market is conventional gas and close to a third is comprised of CSG. Historically, gas production in the Eastern market occurred at fields in the Gippsland (Bass Strait), Otway and Copper Basins. Over the past five years, however, gas production growth in the Eastern market has been underpinned by CSG production, particularly in the Surat-Bowen Basin. CSG production in 2010–11 was estimated to be around 6 bcm (see Figure 3.11).

Figure 3.11: CSG and natural gas production in Australia



Source: ABARES 2011, GA and BREE 2012

The majority of CSG production occurs in the Surat-Bowen Basin (southern-central Queensland). The emergence of the CSG industry in Queensland has been underpinned by the Queensland Gas Scheme (QGS). The QGS was introduced in 2005 and required electricity retailers and other liable parties to source a minimum percentage of their electricity from eligible gas-fired generation. The initial requirement was set at 13 per cent and increased to 15 per cent in 2010. The objective of the scheme was to diversify the state’s energy mix, provide support for the gas industry and reduce greenhouse gas emissions. This scheme will conclude with the introduction of a carbon price from July 2012.

The Eastern market does not currently export natural gas. However, there are a number of LNG projects under construction in Queensland. These will be the first CSG-based LNG projects in the world. The projects include the Curtis Island LNG (8.5 Mt a year; BG Group), Gladstone LNG (7.8 Mt a year; Santos, Petronas, Kogas), and Asia Pacific LNG (9.0 Mt a year²;

2 A positive FID on the second train of APLNG was taken in July 2012

Origin Energy, ConocoPhillips, Sinopec) (see Figure 3.6). Further information on these projects is included in the Annex. Production of CSG is expected to increase substantially over the medium and long term, underpinned by the start up of these CSG-LNG projects.

Gas production in the Gippsland Basin is expected to be supported over the medium term by the development of the Kipper and Turrum projects. Over the longer term, gas production in the Eastern market is projected to increase by an average of 5 per cent a year to reach 64 bcm by 2034–35 (BREE 2011a).

4. LNG pricing and marketing

Spot markets and short term contracts

Spot trade and short term contracts account for around 15-20 per cent of total LNG global trade. The proportion of LNG trades in spot markets and short term contracts, however, are not sufficient to arbitrage differences and drive global gas price convergence (Miyazaki and Limam 2012).

Over the past five years, an increasing proportion of LNG has been traded via spot trading—particularly for sale to European consumers by LNG producers in the Middle East. Spot trading has been supported the increasing availability of LNG shipments that previously were intended for the US market. A significant fall in domestic prices in the US has resulted in LNG suppliers diverting shipments into Europe or Asia, where they can obtain a higher price in the spot market.

North America (the US, Canada and Mexico) has liberalised gas markets and gas-to-gas competition is well established, with prices fluctuating in response to short-term shifts in gas supply and demand. Traded gas prices in the US are set according to the spot price at the Henry Hub. Henry Hub is a junction of numerous gas pipelines on the eastern border of Louisiana, connecting producing and consuming regions, and the location of substantial underground storage capacity. The rapid increase in domestic shale gas production has seen the Henry Hub gas price fall from a peak of US\$12 a GJ in June 2008 to an average of US\$3.80 a GJ in 2011. In April 2012 the Henry Hub price fell below US\$2 a GJ, the lowest level in a decade. The Henry Hub price has also averaged well below any other marker prices in the Atlantic or Pacific. This has encouraged the re-exportation of LNG cargoes bound for the US.

Spot LNG cargoes imported into the UK are often priced against the National Balancing Point, which is now accepted as an appropriate benchmark for pricing LNG imports in Europe. The National Balancing Point differs to the Henry Hub in that it is not a physical location, but rather a virtual trading location. An important factor for the transition to spot pricing has been the increased availability of LNG cargoes that had been destined for the US. Whenever the National Balancing Point gas price remains significantly higher than the Henry Hub price, it has been more profitable to divert LNG to Europe rather than to the US.

Long and medium term contracts

LNG shipments are typically sold under medium to long-term contracts. Long term contracts are desirable for capital-intensive projects because they share the project risk between the buyer and the seller. The buyer takes on the volume risk through 'take or pay' clauses where they are obliged to take delivery of the gas or pay for a specified volume. The seller(s) takes on the risk associated with investing billions of dollars to develop an LNG project, which includes the construction of liquefaction capacity and often upstream infrastructure and field development.

To reflect the risk associated with the development of a multi billion dollar LNG project, contracts covering a significant proportion of annual production are generally agreed to before the final investment decision. Managing risk by guaranteeing sales enables LNG project developers to seek finance and board approval for a final investment decision. Typically, an LNG project developer will negotiate with buyers and sign non-binding agreements (heads of agreements or memorandums of understanding) as the project progresses through design and government approval phases. These agreements are then converted to binding sales and purchase agreements when the LNG developer is confident that the project will go ahead.

Gas-on-gas indices

Gas-on-gas pricing is determined by the interplay of supply and demand of gas at gas hubs. Gas-on-gas priced LNG is more associated with spot markets and short term contracts, but can also be used as the basis for medium and long term contracts. Gas-on-gas pricing accounts for around 30 per cent of LNG trade (IGUSG 2012).

Gas pricing in the North Atlantic, particularly in North America and the UK, has partially decoupled from oil prices. At both the two large trading hubs—the Henry Hub in the US and the National Balancing Point in the UK—gas imports and domestically produced gas can be traded, allowing for price convergence.

Longer term contracts that use gas price indices, rather than competing fuel indices, are emerging in North America. Contracted prices of gas from the Sabine Pass terminal are based on Henry Hub prices, liquefaction and transport costs. This form of pricing is favourable to North American LNG project proponents because the projects are not vertically integrated to the field. The LNG producer transfers price risk to the LNG buyer by contracting an LNG price equal to their supply costs plus a fixed margin. While long term contracts that use gas price indices are presently cheaper than those that use oil-linked pricing, LNG buyers accept greater risk associated with changes in supply costs.

Competing fuel indices – oil linked pricing

Around 70 per cent of world LNG trade is priced using a competing fuel indices (IGUSG 2012). These indices are general based on crude oil or fuel oil, and as such are also referred to as ‘oil price indexation’ or ‘oil-linked pricing’.

The original rationale for oil-linked pricing was that the price of gas should be set at the level of the price of the best alternative to gas. In early markets, the best alternative to gas was typically heavy fuel oil, crude oil or gas oil. Despite the fact that the substitutability of oil and gas has decreased, particularly in electricity generation, arguments remain for the use of oil-linked pricing.

On the production side there is competition of resources between the exploration and production of gas and oil (IGUSG 2012). On the demand side, oil and gas can be substitutable in the heating sector (e.g. Germany) and in the generation of peak and semi-peak electricity (e.g. Japan). Gas is expected to play a more significant role in the transportation industry, and

the competition between oil and gas could increase. In the longer term, technologies such as gas-to-liquids might increase gas to oil substitutability.

Oil prices are less volatile, more transparent and less subject to market manipulation, relative to gas. Shareholders of gas and oil producing companies are comfortable with an oil price related risk profile of their investment. LNG project proponents favour oil-linked contracts to underpin projects with extensive upstream investment. LNG buyers greatly value security of supply and believe that oil-linked prices are more likely to ensure the development of supply projects, relative to alternative priced mechanisms (Miyazaki and Limam 2012). Oil-priced LNG contracts have supported the majority of long term LNG project investments in the past (IGUSG 2012).

Oil-linked pricing is particularly dominant in the Asia Pacific region. Asian LNG contracts, particularly involving buyers in Japan, the Republic of Korea and Chinese Taipei, link the gas price on a basket of crude oils delivered to Japan known as the Japan Customs-cleared Crude (JCC). The formula used in most of the Asia LNG contracts that were developed in the late 1970s and early 1980s can be expressed by:

$$P_{LNG} = \alpha \times P_{crude} + \beta$$

Where, P_{LNG} = price of LNG in US\$/mmBtu (US\$/GJ x 1.055)

P_{crude} = price of crude oil in US\$/barrel

α = crude linkage slope

β = constant in US \$mmBtu (US\$GJ x 1.055)

Historically, there was little negotiation between parties over the slope of the LNG contracts, with most negotiation effort focused on the value of the constant, denoted by β (Holmes 2012).

Following the oil price decline in the mid 1980s, most new LNG contracts incorporated a floor and ceiling oil price that determined the range over which the contract formula could be applied. The price curve was 'S-shaped'. That is, above and below a particular oil price, the LNG price is capped such that producers exposure to low prices are limited while buyers are partially protected from significant increases in the oil price. Over time, these capping points have shifted upwards, and the relationship between oil and gas prices at different oil prices have altered as well. From the late 1990s, there was a departure from traditional Asian LNG pricing, with both the value of the slope and constant up for negotiation.

At present, there are three possible reasons why the Asian market has not followed the North Atlantic market where gas and oil prices have started to decouple.

1. LNG producers still require pricing certainty given the costs and associated risks of developing LNG projects. LNG projects in the Asia-Pacific region, particularly those in Australia, are vertically integrated. The projects include the construction of the liquefaction facility, in addition to the development of fields and transmission infrastructure. Given the increase in capital costs for developing LNG projects over the past decade, mechanisms for guaranteeing returns for LNG producers are as important as they have ever been. While this does not require that gas prices be linked to the oil price, it supports a long-term contract price which 'locks in' the existing mode of pricing for the duration of the contract.
2. In order for gas and oil prices to decouple, there needs to be an alternative mechanism on which to base prices. This mechanism needs to be transparent to ensure that no party (buyer or seller) is disadvantaged at price settlement. There is currently no suitable alternative mechanism in the Asian market, and in the case of Japan, little prospect of one developing in the short term.
3. Buyers, particularly in Japan and the Republic of Korea, have limited import options and are currently constrained to LNG-based imports. Several Asian LNG players are hesitant to endorse gas index long term contracts due to their potential long term price volatility. They fear that supply projects are more likely to fall behind schedule, thereby jeopardising security of supply, under such alternative pricing mechanisms.

Outlook for gas prices

Gas-on-gas LNG spot pricing may become more prevalent over the medium term as increased capacity from North America and Australia increase the quantity of LNG available on the spot market. Some weakening in spot prices is expected as this new capacity is absorbed into the market (Holmes 2012). However, for the foreseeable future, an oil-linked gas pricing mechanism is likely to remain dominant for long term contract pricing in the Asia Pacific market. BREE understands that the majority of long term sales and purchase agreements that have underpinned the recent final investment decisions of Australian LNG projects are linked to oil prices. These contracts generally cover a period of 15–20 years.

As part of its modelling for the World Energy Outlook (2011a), the IEA adopts a crude oil price assumption of \$120 a barrel in 2035 (in 2010 dollars). The equivalent landed Asian gas price under an Australian contract is likely to be around US\$16 a GJ (in 2010 dollars) in 2035.

A transition away from oil-linked long term contracts could occur over an extended period of time through expiry of existing contracts. However, it would be 25 years before the last contracts expire. Any potential renegotiation of pricing clauses is unlikely in the short or medium term provided suppliers are able to meet their contracted deliveries. Before an LNG exporter would agree to change a pricing clause it would need to be convinced that the new mechanism provided the appropriate level of security and return. The alternative pricing mechanism would need to be transparent to both buyers and sellers.

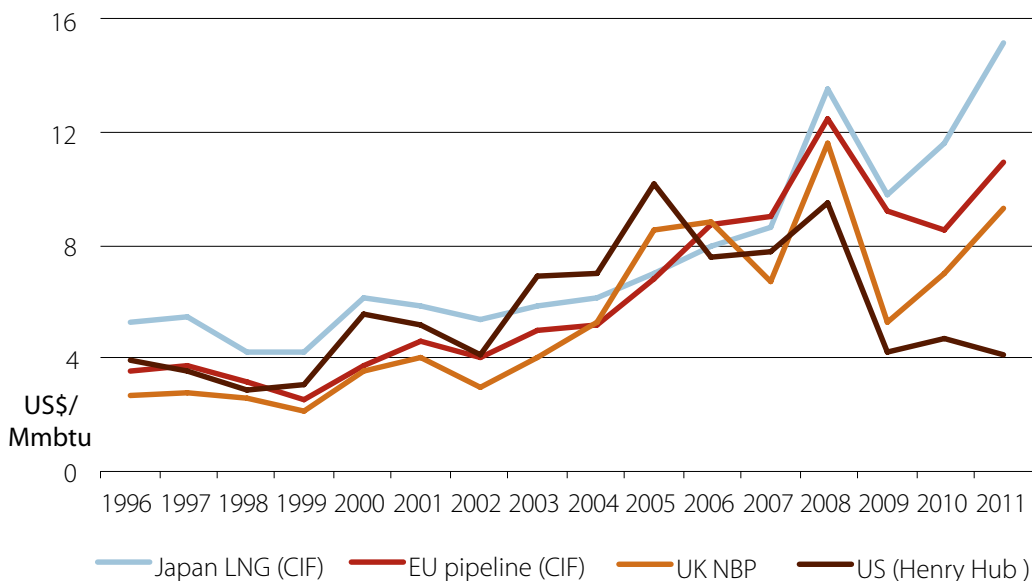
Over the next decade, a small quantity of LNG is likely to be exported from North America under long term gas contracts using gas index pricing. North America may also become one of Australia's gas export competitors over the longer term. At the current Henry Hub price of around US\$2 a GJ, which equates to a landed Asian price of around US\$7–8 a GJ, US gas is

considerably more competitive than exports from Australia. At a Henry Hub price of US\$5 a GJ, the landed Asian prices equates to US\$11 a GJ. At a JCC price of US\$110–115 a barrel, landed Asian prices for Australian oil-linked gas equate to around US\$15–16 a GJ.

Given an assumed crude oil price of US\$120 a barrel in 2035, exports from the US will likely be more cost competitive relative to Australian oil-indexed contracts for all Henry Hub prices less than US\$8–9 a GJ (in 2010 dollars), depending on the transport route.

In recent years, regional gas prices have diverged (see Figure 4.1). Oil-linked Asia-Pacific LNG prices, particularly the Japan Imported LNG price, have increased. Spot prices demonstrate greater volatility and have decoupled from contract prices. The Henry Hub price fell sharply as the demand for gas started to decline and more supply has become available (IGUSG 2012).

Figure 4.1: Regional gas and oil prices



Source: BP 2012

5. Tightening of the domestic eastern gas market

LNG projects connect domestic gas markets to international LNG markets and increase the competition for domestically produced gas. Access to international markets and relatively high LNG prices in the Asia Pacific region have encouraged long-term contracts of large quantities of gas for export and the development of CSG reserves. Higher export prices will likely raise the wholesale gas price paid by Australian domestic consumers, such as gas-fired electricity generators.

Market participants and observers have recently noted the possibility of a 'tight' Eastern market from 2015 to 2020. This potential tight market could arise from:

- forecast growth in domestic gas demand;
- contracted export supplies of LNG from 2015; and
- possible delays in the development of CSG resources over the near term.

At present there is a debate regarding the adequacy of future domestic production in meeting demand from domestic markets and export contracts. The Energy Supply Association of Australia and suppliers, such as Origin Energy, state that there will be sufficient domestic production for both domestic and export markets (ESAA 2012 and Origin 2012a). However, AGL argues that while current reserves are adequate to meet projected demand, those reserves must be brought into production (AGL 2012). Rio Tinto, a large gas consumer, argues that a number of LNG projects may be short on gas reserves, are reliant on the conversion of potential contingent resources to reserves, and that many of the gas resource estimates, including the AEMO's Gas Statement of Opportunities (GSOO), are overly optimistic (Rio Tinto 2012).

Growth in Queensland's CSG production capacity was severely hampered by the 2010–11 flooding, which posed significant challenges for access to and drilling of wells. Wet weather conditions reduced drillers' ability to use multi-well operations, and handle co-produced water. Tighter regulatory controls may have also added to land access difficulties. As a result, fewer wells have been drilled than originally planned, delaying the ramp-up of gas supplies for the CSG-LNG facilities under construction at Gladstone.

The development of CSG resources has also been constrained by regulatory approval processes. As a result of landowners' concerns about the potential impacts of CSG extraction on the natural resources, notably water resources, and the effects on established agricultural industries, measures restricting CSG activities that include drilling, as well as additional regulatory hurdles, have been introduced.

The Queensland and New South Wales governments have recently introduced policies to ensure the protection of prime agricultural land. The Queensland Government has introduced a Strategic Cropping Land Policy Framework which aims to provide a balance between

protecting prime agricultural land while allowing for the development of the CSG industry. The New South Wales Government has implemented a Gateway Process, which requires CSG development proposals on or within two kilometres of strategic agricultural land to be assessed by an independent expert panel prior to proceeding with development applications. Agricultural Impact Statements are also required from developers to demonstrate that impacts on agricultural land and resources are avoided or minimised to acceptable levels.

Resources companies, including CSG proponents, dependent on port developments and shipping in the Great Barrier Reef World Heritage Area (GBRWHA) are concerned about delays to their assessments under the Commonwealth *Environmental Protection and Biodiversity Act 1999* (EPBC Act). These delays may arise from the strategic assessment of the GBRWHA by the Australian and Queensland Governments and the United Nations Educational, Scientific and Cultural Organization (UNESCO). The strategic assessment comprises both a marine component and coastal component. The Great Barrier Reef Marine Park Authority (GBRMPA) is leading the marine component and the Queensland Government is undertaking the coastal component which includes urban, industrial and port development.

The recently announced Australian Government funded Independent Expert Scientific Committee will provide publically disclosed advice to governments on relevant CSG development proposals where they may have significant impacts on water resources. Under the terms of the new National Partnership Agreement on Coal Seam Gas and Large Coal Mining Developments, when considering CSG developments Commonwealth and state and territory regulators are required to take into consideration advice provided by the Committee on relevant proposals. Under draft amendments to the EPBC Act currently before Parliament, the Committee will have two months to provide its advice on individual development proposals. States and Territories that sign the National Partnership Agreement have until 30 September 2012 to finalise protocols on how they will implement its terms.

Although the Independent Expert Scientific Committee will promote community confidence in CSG developments and ensure the sustainability of the sector, it will increase uncertainty over the timelines for approvals under Commonwealth, State and Territory regulation, processes and policies.

The commencement of exports from the three LNG facilities at Gladstone will be underpinned by incremental increases in production following the development of CSG reserves. If ramp-ups to production capacity are delayed, a proportion of gas supplies that would otherwise have been available in the domestic market may be exported.

While the Eastern gas market is likely to tighten over the next five years, overall gas availability does not appear to be the issue. Rather, it appears to be a question of price. In May 2012 Origin Energy announced a major gas sales agreement with GLNG, operated by Santos and due to start exporting LNG in 2015. Under the agreement, Origin will supply GLNG with 365 PJ (9.4 bcm) of gas over ten years from 2015, with the gas sources from Origin's east coast portfolio (Origin Energy 2012b). The Origin/GLNG agreement highlights the availability of gas *if* purchases are willing to pay oil linked prices. At US\$100 a barrel, an oil linked price equates to around \$7 a GJ and is a much higher price than many industrial consumers are currently paying. This suggests that consumers in the Eastern Gas Market will need to adjust to higher prices.

The process of adjustment will depend on the consumers' sensitivity to changes in gas prices.

Wholesale gas consumption is relatively inelastic to increases in prices. Existing mining and industrial consumers, such as the alumina/aluminium and non-ferrous metals industries, are unlikely to substantially reduce their consumption of gas, as their demand is highly inelastic to changes in price. Consumption of gas within the residential sector is also price inelastic. Higher wholesale gas prices, however, would likely have a large impact on users where gas is an important component of overall operating costs such as fertiliser and ammonia plants. The iron and steel industry and the basic chemicals industry are also likely to be relatively responsive to increases in gas prices. In the electricity sector, substantially and prolonged higher gas prices may also make it unprofitable to construct new gas-fired electricity plants.

While a tightening Eastern gas market is likely in the short to medium term, increased access to international markets and higher prices are likely to encourage the further development of reserves and increase production over the medium to longer term. This, in turn, should moderate gas prices as supplies increase.

6. Domestic gas prices

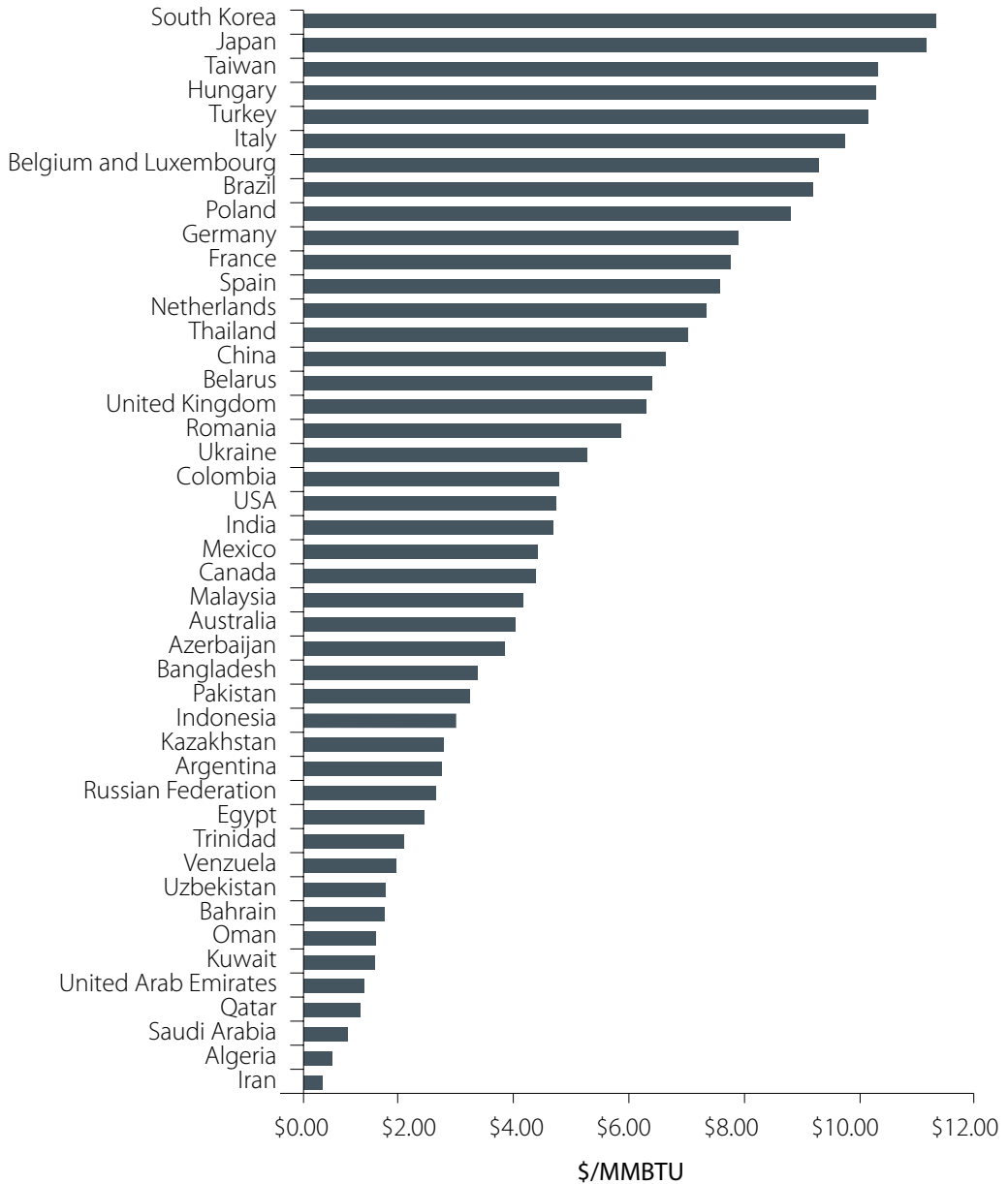
Historically, long-term contracts were the principal instrument for trading gas domestically. Long-term contracts were preferred because they provided investment certainty to the producers of large gas field developments as well as gas users, such as electricity generators. The pricing structure for many of these contracts was based on the cost of gas production plus an annual price escalator such as the consumer price index.

Many long-term contracts, of 30 years or more, were negotiated when fields were developed in the 1970s and 1980s and the cost of field development and production was considerably lower compared to the present. The offshore fields that were developed at this time were generally close to land and not as far below the seabed. This also contributed to lower development and production costs.

Factors determining domestic gas prices

Australia's wholesale gas prices are low by international standards (Figure 6.1). However, in recent years, Australian retail gas prices have increased (Figure 6.2).

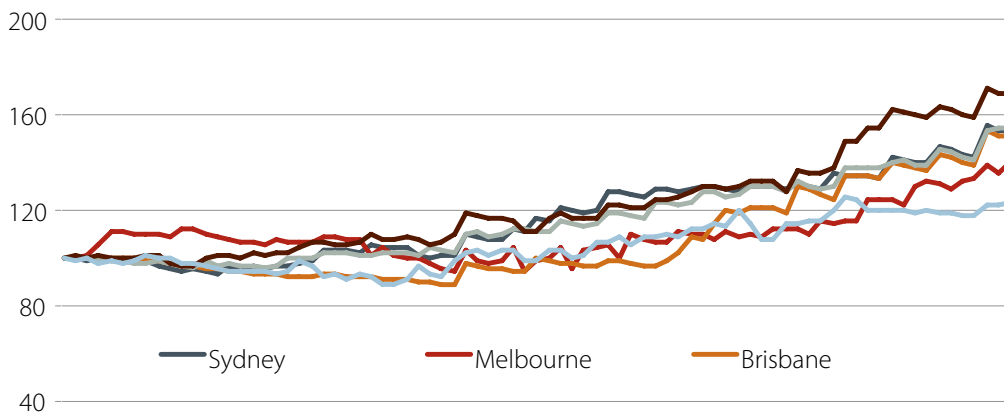
Figure 6.1: Average 2010 wholesale gas price by country



Source: Adapted from IGUSG 2012

A potential tightening of the Eastern market, over the short to medium term, will continue to place upward pressure on prices. This section examines the factors determining domestic gas prices with a particular focus on the Eastern market, including the factors affecting supply, demand, market competition and transparency.

Figure 6.2: Eastern market retail gas price index

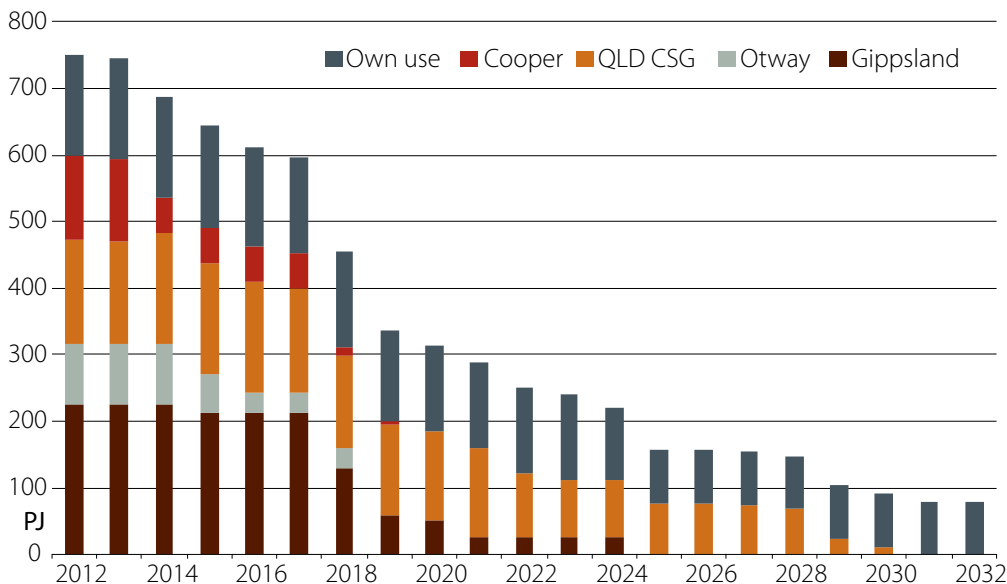


Source: AER 2011

Expiration and renegotiation of long-term contracts

A significant proportion of long-term gas contracts in the Eastern market expired within the last five years, and more are due to expire in the next five years (see Figure 6.3). As the proportion of domestic gas underwritten by low priced mature long-term contracts decreases, the average wholesale price increases. BREE's understanding is that a large proportion of NSW purchasers of wholesale gas will need to renew contracts by 2018.

Figure 6.3: East coast domestic gas contracts



Source: EnergyQuest 2012

Given the current price disparity between domestic and export prices, and the development of export terminals on the eastern coast, producers generally prefer to negotiate export contracts which have higher prices relative to domestic prices. Increasingly, producers prefer to sign shorter (five year) contracts with domestic users, as producers wait to see how LNG exports will affect market dynamics from 2014–15.

Existing long-term domestic contract prices range between \$3.50-4.00 per GJ in 2011 in the Eastern market (AER 2011). However, renegotiated contracts are characterised by higher prices, underpinned by rising production costs and competition from LNG exporters.

Increasing domestic and export demand for gas

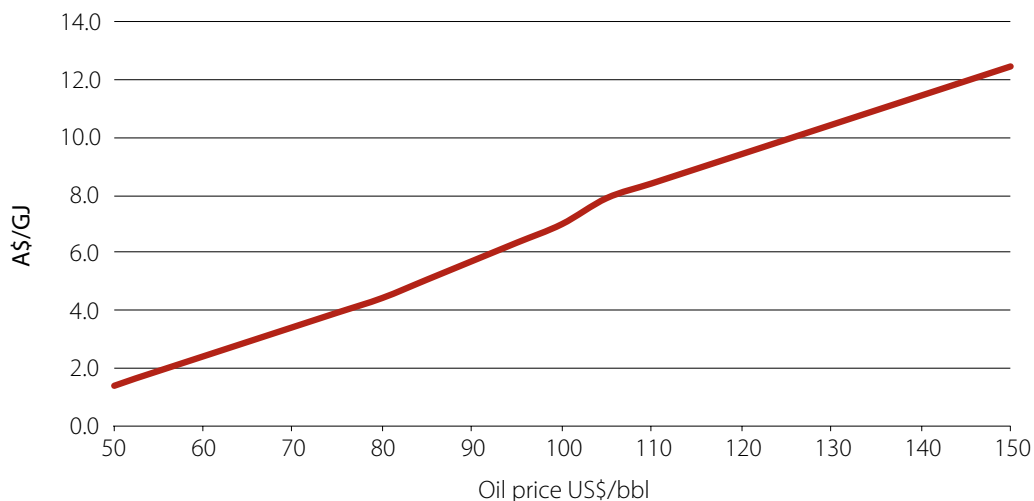
Increasing demand for natural gas—both for domestic consumption and for exports—will underpin increases in Australian domestic gas prices. Australia's gas consumption is projected to double between 2008–09 and 2034–35, while exports of LNG will increase nearly seven fold over this period. Exports of gas from the Eastern market are scheduled to start in 2014 and reach 25 Mt per year at the end of the decade. The commencement of LNG exports, and the netback prices received by producers, will influence domestic gas prices in the Eastern market.

Once operational, CSG LNG projects will connect Australia's eastern gas market to the Asia-Pacific market. These projects will increase the demand for domestically produced gas and put upward pressure on domestic prices, which should converge over time to the netback price of LNG export prices received less the transport, marketing and liquefaction costs.

Netback prices will vary depending on how LNG prices are set. For example, the value of LNG from the three projects in Queensland is linked to oil prices. The netback price into the Eastern market is shown in Figure 6.4. As an example, the netback price is based on shipping cost of US\$0.75 a GJ, a liquefaction cost of US\$5.10 per GJ and an exchange rate of \$1.02.

At an oil price of US\$80 a barrel, the LNG price in Asia is around US\$10.40 per GJ, which after deducting shipping and liquefaction costs, equates to a netback price of around A\$4.40 per GJ in eastern Australia. Conversely, at an oil price of around US\$120 a barrel (which the IEA assumes under its New Policies Scenario in 2035) the Eastern market netback price is about A\$9.40 per GJ.

Figure 6.4: Oil linked LNG netback prices to the Eastern market



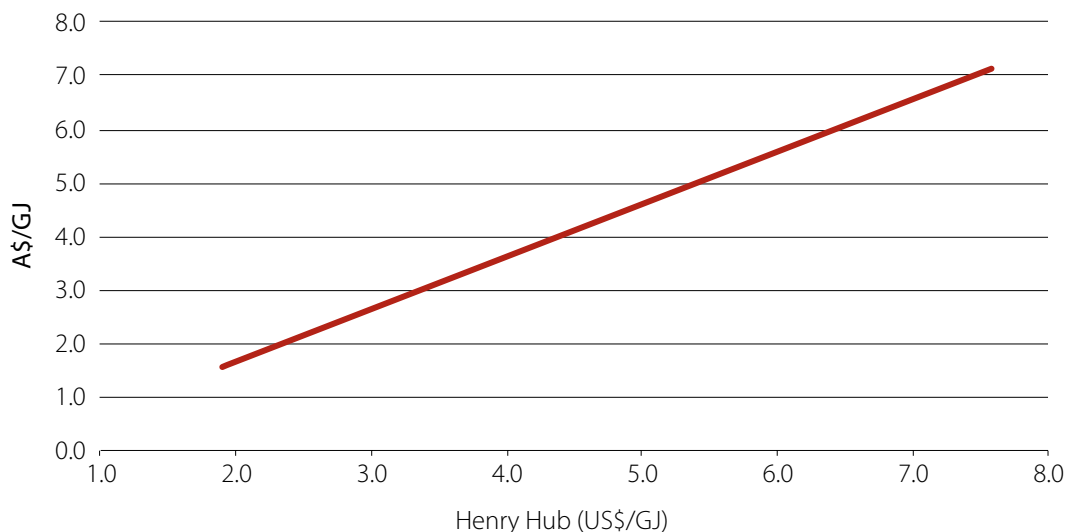
Source: BREE

It is possible that Asian LNG could become more closely linked to the Henry Hub gas price over the longer term. This might arise if there were to be a significant quantity of LNG exported from the US to Asia. US exports could be priced based on the Henry Hub price plus a liquefaction cost of around US\$2.35 a GJ and also a shipping and a fuel cost of US\$3.20 a GJ (Cheniere Energy 2012). If LNG prices in Asia become more closely linked to the Henry Hub gas price, a lower netback price could be expected in the Eastern market. At current Henry Hub prices of around US\$2.00 a GJ, it would be possible for gas to be delivered to Asia at around US\$7.60 a GJ. If this were to become the basis for the Asia-Pacific gas price this would equate to a netback price in the Australian Eastern market of about A\$1.65 a GJ.

A Henry Hub price of US\$2.00 a GJ is unlikely to be sustainable over the medium or long term. US gas producers are unable to cover their capital costs at low gas prices, and are deterred from increasing supply. Further, low Henry Hub gas prices encourage exports from the US to where gas prices are much higher.

Industry analysts estimate that Henry Hub prices will, over the longer term, average at least US\$4.00–5.00 per GJ (in 2012 dollars). If these markets were to be linked via US exports to the Asia-Pacific where the price were to be set by the long-term expected Henry Hub price, this would equate to an Eastern Australian market LNG netback price of A\$3.50–4.50 a GJ (see Figure 6.5).

Figure 6.5: Henry Hub linked LNG netback prices to the Eastern market



Source: BREE

In the event that Asian LNG prices become largely based on low Henry Hub prices, lower netback prices to the Australian domestic market would reduce the economic viability of additional Australian LNG projects. It could also render further investment in a number of gas fields uneconomic.

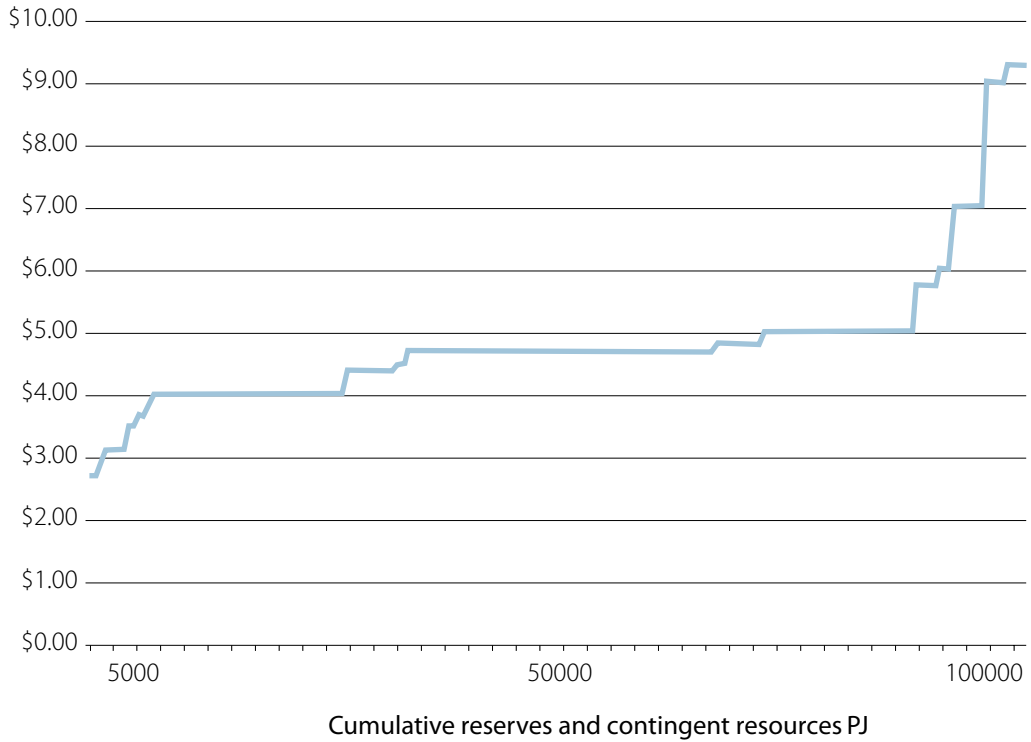
Increasing production costs

A contributing factor to increased gas prices is the growing cost of production. Increasing costs reflect production from natural gas fields that are in deeper water and further from the coast than previous offshore developments. This will result in higher construction and operating costs relative to existing fields.

The cost of CSG production is also expected to increase as the lower cost resources are exploited first. The planned LNG projects in the Eastern market are expected to require about 800 bcm (31 040 PJ) of feedstock over their life.

EnergyQuest estimates that gas production costs are at or below \$5 per GJ (see Figure 6.6) for cumulative reserves and contingent resources below 80 000 PJ (2062 bcm). To give an indication of the scale of these reserves and resources, cumulative production of gas on in the Eastern market between 2008–09 and 2034–35 is projected to be 46 000 PJ (1186 bcm).

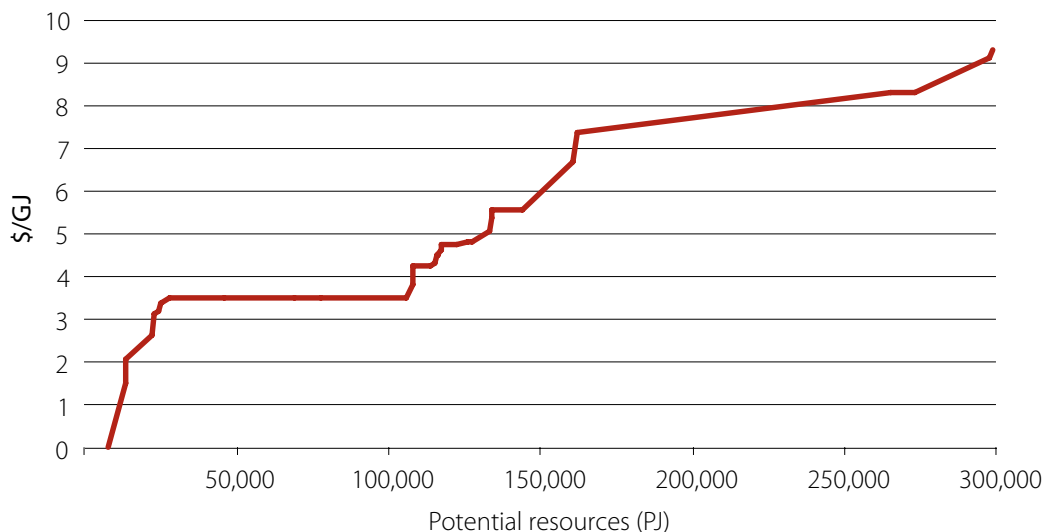
Figure 6.6: Estimated Eastern gas production costs per GJ



Source: EnergyQuest 2012

Core Energy (2012) recently provided AEMO with an analysis of the gas production costs for major identifies resources in Eastern Australia. They estimate that over 100 000 PJ (2577 bcm) of gas can be extracted at less than \$4 a GJ (see Figure 6.7).

Figure 6.7: Estimated Eastern market gas production costs (Core Energy 2012)



Source: Core Energy 2012

Increasing production costs puts upward pressure on wholesale gas prices. Nevertheless, a given percentage increase in production costs will not translate into an equal percentage increase in retail gas prices. Table 6.1 shows that wholesale costs account for around a third of the total retail costs, with network charges accounting for almost half of this amount.

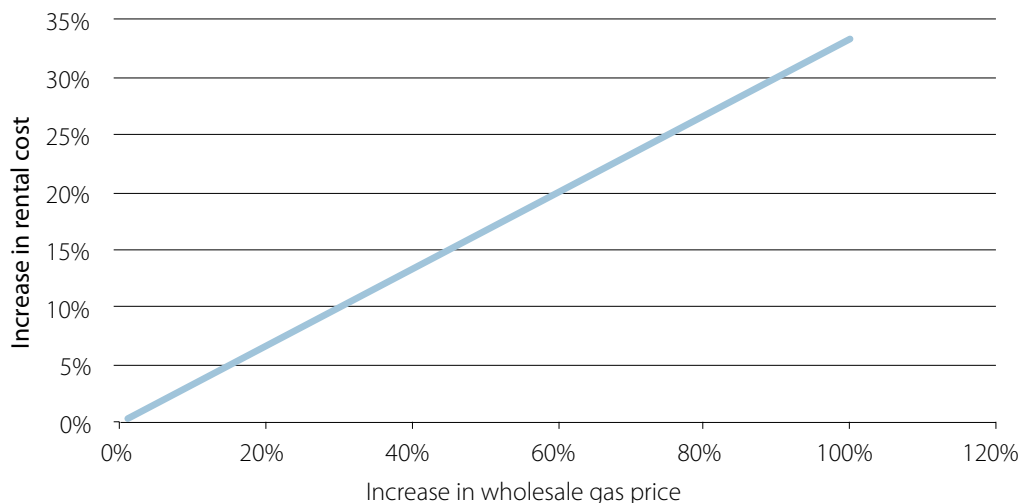
Table 6.1: Breakdown of retail gas prices in NSW

Wholesale costs	Network	Retail operating costs	Retail margin
33%	47%	13%	7%

Source: AER 2011

Figure 6.8 shows that, at existing prices, a 25 per cent increase in the wholesale gas cost should result in an 8 per cent increase in the retail price. A doubling of wholesale costs would result in 33 per cent increase in the retail price.

Figure 6.8: Effect of increases in wholesale gas costs on retail costs



Source: BREE

Constraints on CSG production

High export prices and projected increases in wholesale gas prices will encourage producers to expand CSG resources and production. However, delays to exploration and production approval processes can impact gas prices in two ways. First, if the affected gas field were dedicated to an LNG project in Queensland, the delays may result in the LNG plant securing additional supplies from sources that might otherwise be used to supply the domestic market. Second, slow or complicated approval processes may result in delays to the development of CSG resources as is currently the case in the Gunnedah and Gloucester basins of NSW. Production from these basins would be important to supply gas to NSW consumers from the middle of this decade. Delays to the start of significant production from these fields could limit gas availability which, in turn, could put upward pressure on prices.

In 2009–10, NSW produced 6 PJ (155 mmcm) and imported 95 per cent of its gas requirements from other states. Historically, NSW has not been a significant gas producer. Any future increases in gas consumption will need to be based on CSG as there are no conventional reserves of gas. Current constraints to increasing CSG production in NSW require NSW based purchasers of gas to continue sourcing supplies from interstate (e.g. Cooper or Gippsland Basins). Despite its small current level of production, NSW has the opportunity to greatly expand production. For instance, the marginal cost of gas production from NSW basins (Gunnedah, Gloucester or Sydney) is estimated to range from \$2.70–5.00 per GJ (EnergyQuest 2012). By contrast, production costs in the Gippsland or Cooper Basin are estimated to be above \$4.00 per GJ and there would be significant transport costs to consumers in NSW from these two out-of-state Basins.

Streamlining of CSG regulatory control

Price increases associated with the projected tightening of the Eastern market could be moderated through the adoption of streamlined regulatory frameworks that still continue to provide appropriate environmental guarantees. Prompt streamlining of regulatory controls while also maintaining appropriate environmental standards should reduce serious delays to development schedules and help control upward pressure on gas prices.

Increasing network charges

Domestic retail gas prices are comprised of wholesale costs, network charges, retail operating costs and a retail margin. Wholesale gas prices are an important determinant of retail gas prices. Nevertheless, the network component typically comprises around half of retail gas prices.

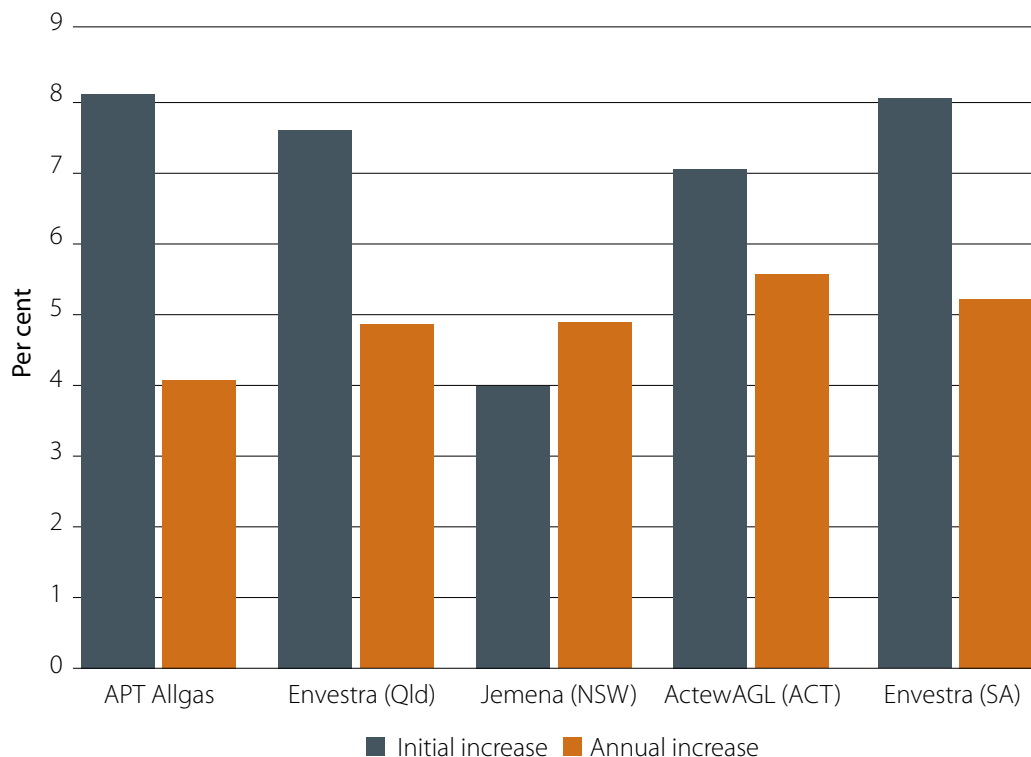
The network component consists of the costs associated with:

- maintaining, replacing and extending transportation equipment, gas pipelines;
- maintaining and reading meters;
- operating the distributor, including labour, materials, compliance with various government standards;
- finance for new investment and refinancing; and
- complying with government legislation.

The Australian Energy Regulator (AER) is the economic regulator of covered distribution and transmission networks in the Eastern market for the duration of each access arrangement period of five years. The commencement date for the access arrangement periods differs by state.

Rising capital and operating expenditures are expected to increase distribution network charges in current access arrangement periods beyond levels in previous periods. The AER's latest decisions to increase network charges are expected to raise retail gas prices by 4–8 per cent in the first year of the access arrangement period, and a further 4.1–5.5 per cent for each subsequent year of the access arrangement period (see Figure 6.9) (AER 2011).

Figure 6.9: The effects of higher network charges on retail gas prices (nominal)



Note: Price impact estimate is for a typical residential customer.

Source: AER 2011

Market competition and transparency

The uptake of gas-fired electricity generation in the Eastern market may change the nature of competition in the electricity and gas sectors, as companies integrate vertically into gas production. For example, Origin Energy and AGL have increased their interest in the upstream gas industry, possibly to hedge against the risk of future gas price increases given their operations in gas retailing, gas-fired electricity generation and LNG projects.

Given the commercial nature of the contract negotiations between suppliers and consumers, there is very little publicly available contract price data to assess the competitiveness of gas markets. Nevertheless, gas spot markets are a recent and valuable addition to Australia’s gas market framework, especially in terms of the price information that they provide and their ability to improve price transparency. Spot markets exist in the Victorian Wholesale Gas Market and Short Term Trading Market hubs in Adelaide, Sydney and Brisbane. Other tools managed by the Australian Energy Market Operator (AEMO) to increase market transparency include the Gas Bulletin Board the annual Gas Statement of Opportunities (GSOO).

Australian gas reservation policies

In the Western market, where the NWS LNG project connected the domestic market to the international LNG market in 1989–90, the Western Australian Government has implemented a domestic gas policy.

Prior to 2006, two state agreements underpinned the domestic gas policy, one with the NWS LNG project and another with the upcoming Gorgon LNG projects. The obligations of the NWS Project under the original NWS Project Agreement expire with the completion of the contract in 2014. However, the NWS project is expected to continue to supply domestic consumers under provisions within the agreement for further supplies to be negotiated. The Gorgon project is also committed to supplying 2000 PJ (52 bcm) of gas into the domestic market over the life of the project. To meet this obligation, the project has a domestic gas plan processing capacity of 110 PJ (2822 mmcm) a year. Delivery of 55 PJ (1411 mmcm) a year will commence at 31 December 2015 with the balance to be supplied by 2021. Supply is subject to commercial viability provisions.

In 2006, a formal 'WA Government Policy on Securing Domestic Gas Supplies'—reservation policy—was adopted. Under this policy, project proponents are required to reserve up to 15 per cent of production for supply to the domestic market. The reservation policy allows for case-by-case flexibility, allowing potential producers to negotiate with the WA government as to the amount to be reserved and the manner in which it is to be supplied, including consideration of market mechanisms designed to provide gas producers with flexibility in meeting their commitments. The reservation policy is designed to ensure the availability of gas to the domestic market, but does not directly constrain price. The price continues to be negotiated between producers and consumers on commercial terms (Energy Quest 2010).

Under the current Western Australia agreements, the Pluto project is also obligated to sell gas into the domestic market. However, under its agreement with the state government, the sales do not need to start until its second train is in operation. As yet there is no firm timing for a final investment decision or operation of a second train at Pluto. The Pluto LNG project is the first to be subject to the new reservation policy. The details of the reservation policy, as it will be applied to Wheatstone and the potential Browse and Scarborough projects, are still under negotiation (EISC 2011).

It is claimed that the construction of CSG-LNG facilities in Queensland has made it difficult for domestic consumers in the Eastern market to secure long-term contracts at historically low prices. This has prompted a discussion of a similar policy response, with a NSW Parliamentary Committee recommending in May 2012 that NSW implement a domestic gas reservation policy modelled on that introduced in Western Australia (NSW Parliament 2012). This poses a challenge for NSW because it imports over 90 per cent of its gas from other states and such a policy could deter exploration and investment in gas development in NSW.

Economics of domestic gas reservation

A domestic gas reservation policy imposes both short and long-term effects if the LNG netback price exceeds domestic gas prices, with potentially adverse impacts on the long-term domestic price of gas.

In the short term, a reservation policy diverts gas from the export market to the domestic market, increasing domestic supply and placing downward pressure on domestic gas prices. Lower domestic prices for an extended period of time induce increased domestic consumption of gas and promote greater investment in the development of the downstream industry. These investments, however, may only be viable so long as the reservation policy remains in place that provides for a lower than export price of gas. The benefits to wholesale consumers of gas are also more than offset by the losses to domestic gas producers who are obliged to sell their product at a lower price than they would otherwise. This reduces the returns to producers whose investments generated the increased gas supplies for export that, in turn, led to a domestic reservation policy.

In the longer term lower gas prices due to a domestic reservation policy reduce market returns to producers and lower their incentive to make further investments that would help shift the future supply curve of gas downwards. Thus, over the long run, gas reservation policies can lower investment in further gas supply developments and result in higher domestic gas prices than otherwise.

Lobbying to affect the reservation targets could also result in a dissipation of part of the resource rent that would otherwise be available to the upstream gas industry. Overall, this redistribution in resource rent would be achieved at a net cost to the Australian community.

Gas price projections

There is a very wide variation in the projected gas prices in Australia among market analysts. Differences in prices arise from the use of different models, assumptions and parameters. Gas price forecasts are also highly variable and have changed markedly over recent years even when developed by the same analysts.

ACIL Tasman gas price assumptions

ACIL Tasman (2010) used their gas model to derive long-term price projections into the Eastern and Western gas markets using five different scenarios. These scenarios differ in terms of a high or moderate Australian and world GDP, the oil price, the LNG price, and market competitiveness.

Table 6.2: provides ACIL Tasman's (2010) gas price projections in the Eastern and Western markets under the central 'planning scenario'. They project that the Eastern and Western market prices will converge by 2030, under the normal expected Australian economic conditions over the course of the scenario.

Table 6.2: Projected gas prices, 2010\$/GJ

	Eastern market	Western market
Year	\$/GJ	\$/GJ
2012	5.20	8.10
2015	5.50	7.50
2020	6.20	7.60
2025	7.00	8.00
2030	7.50	7.90

Source: ACIL Tasman 2010

ACIL Tasman observes that the reason for recent gas price rises in Western Australia is *not* because of exposure to LNG export competition, but due to recent shortages in gas supply as a result of a lack of gas processing capacity. ACIL Tasman projects that with the relaxation of this constraint in the medium-term, Western Australian gas prices will moderate.

In late 2011, ACIL Tasman developed projections for gas prices for the Australian Energy Technology Assessment. These projections feature higher prices in the Eastern market by 2030 than ACIL Tasman projected in 2010 (see Table 6.3).

Table 6.3: Projected Eastern market gas prices, 2012-13\$/GJ

	QLD	NSW	ACT	VIC	SA	TAS	SA
	Brisbane	Wilga Park	Canberra	Melbourne	Adelaide	Bell Bay	Moomba
2012-13	6.28	6.00	5.48	4.92	5.71	5.35	5.64
2015-16	7.76	6.85	6.07	5.53	6.45	5.96	6.59
2020-21	8.74	7.92	7.66	7.15	7.90	7.58	7.68
2025-26	9.86	9.23	9.44	8.96	9.47	9.39	9.01
2030-31	10.96	10.52	10.78	10.31	10.81	10.74	10.31

Source: ACIL Tasman 2011a

In February 2012, ACIL Tasman developed an updated set of projections for gas prices as an input into AEMO's transmission and planning and the Australian Energy Technology Assessment. These latest projections feature higher prices by 2030 than ACIL Tasman projected in 2011 and are provided in Table 6.4.

Table 6.4: Projected gas prices, 2012-13 \$/GJ

Region	SQLD	NQLD	NSW	VIC	SA	TAS	NT	SWIS	NWIS
2012	6.8	6.4	6.4	5.4	6.4	5.8	11.0	11.7	10.64
2020	9.4	9.3	8.6	7.7	8.7	8.2	11.0	13.9	12.88
2030	11.9	12.0	11.7	11.0	11.8	11.5	11.0	12.3	11.29

Source: ACIL Tasman 2012

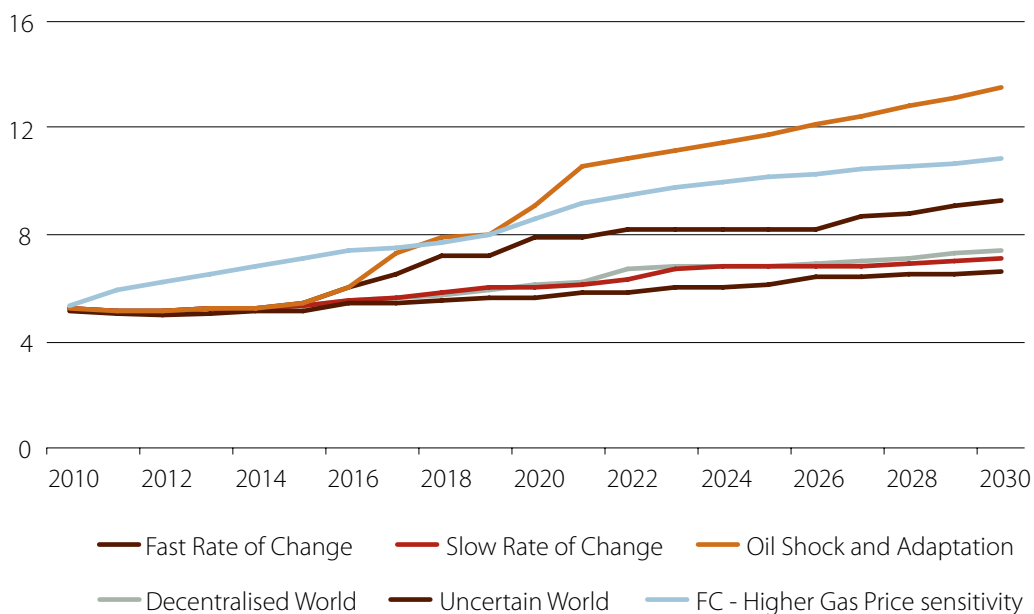
IES/AEMO gas price assumptions 2011

In a report to AEMO, Intelligent Energy Systems (IES) projected Eastern market gas prices to start at \$5.68 per GJ in 2011 and reach \$8.73 per GJ in 2030, in 2011 dollars (IES 2011).

For the 2011 GSOO, AEMO used Eastern market gas price projections prepared by ACIL Tasman in 2010 for its own modelling scenarios. Figure 6.9 shows representative gas price projections for this sensitivity and all scenarios.

Scenarios outlined in Figure 6.9 include the The Fast Rate of Change scenario, Decentralised World Scenario and the 'Slow Rate of Change' scenario. The 'Fast Rate of Change' scenario describes a world where greenhouse gas emission reduction targets have been agreed to achieve a global carbon dioxide equivalent emission concentration not exceeding 450 parts-per-million (ppm) combined with a high level of sustained economic growth in Australia. The 'Decentralised World' scenario describes a world where Australia's energy network becomes highly decentralised by the end of the 20-year outlook period. This scenario assumes a medium carbon price and moderately high oil prices. The 'Slow Rate of Change' scenario describes a world characterised by a low rate of economic growth, both domestically and internationally, with gas prices similar to those in the 'Decentralised World' scenario.

Figure 6.10: Representative gas price projections used for AEMO planning scenarios



Source: AEMO GSOO 2011

ACIL Tasman

ACIL Tasman was commissioned to provide a fuel price assessment for BREE's Australian Energy Technology Assessment to be released 31 July 2012. ACIL Tasman provided gas prices in three different scenarios; low, medium and high (Figure 6.11 a-c). In the low scenario on the east coast in 2030 prices range from \$7.95 per GJ to \$9.48 per GJ, while in the high scenario they range from \$15.31 per GJ to \$16.77 per GJ. In the western market, gas prices in the low scenario in 2030 range from \$8.47 per GJ to \$9.22 per GJ, while in the high scenario they range from \$14.11 GJ to \$15.37 per GJ.

Figure 6.11(a) Gas price assumptions 2012

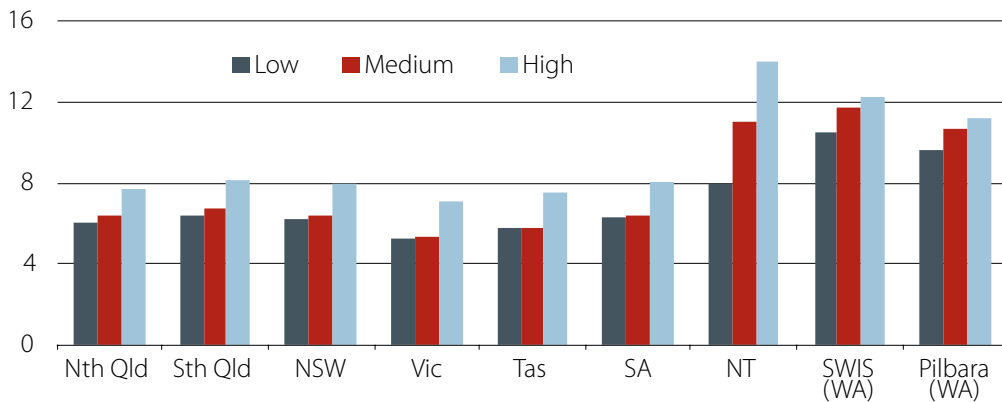


Figure 6.11 (b) Gas price assumptions 2020

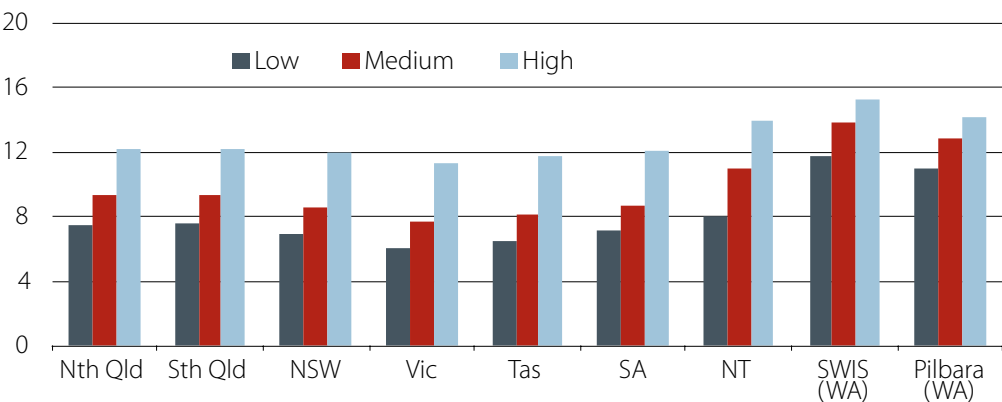
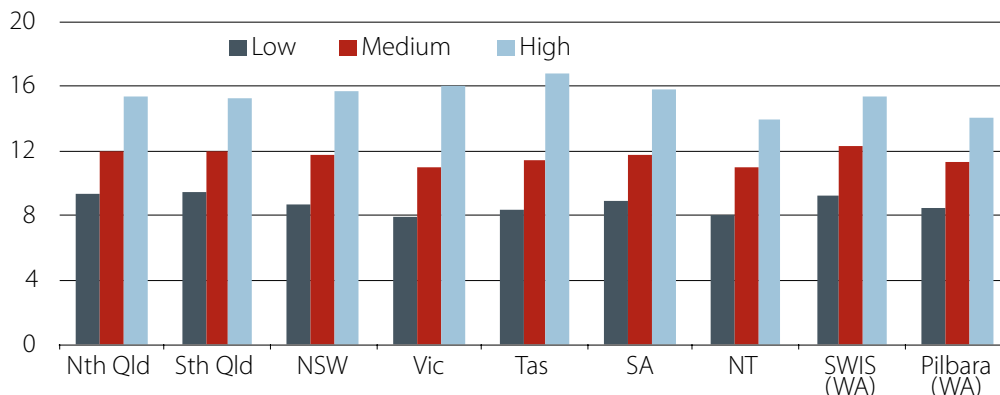


Figure 6.11 (c) Gas price assumptions 2030



Source: ACIL Tasman 2012

Gas prices in the Western Energy market are not widely published and are often confidential in nature. SKM-MMA gas prices for the Western market range between \$6 per GJ and \$9 per GJ for new base-load contracts (SKM-MMA 2011).

SKM-MMA prices were developed using a separate model that replicated the features of the Australian wholesale gas market. The model reflects the existence of limited gas producers that have opportunities to exercise market power, the dominance of long-term contracting, the development of a network of regulated and competitive transmission pipelines, and market growth driven by gas-fired generation and large industrial projects (SKM-MMA 2011). Their model projected substantial increases in gas prices within the Eastern market between 2013 and 2017.

Australian Treasury gas price assumptions 2011

The Australian Government Department of The Treasury employed two models for its energy projections modelling: SKM-MMA and ROAM (Treasury 2011). Both these models assumed gas prices exogenous to the model. SKM-MMA assumed that real gas prices rise to \$9 per GJ in 2030 (in 2009–10 dollars). ROAM’s model assumes real gas prices increase to \$9.30 per GJ by 2030 (in 2009–10 dollars). Both these models assumed the same prices both for the Eastern and Western markets.

Summary of gas price assumptions

Table 6.5 summarises the assumptions and projected gas prices of the different models in 2011-12 dollars. The Eastern market gas price projections range from a low of \$5.8 per GJ by 2030 to a high real price of \$11.7 per GJ by 2030. In the Western market, price projections range from a low of \$7.9 per GJ by 2030 to a high real price of \$11.8 per GJ by 2030.

Table 6.5: Summary of gas price assumptions by various analysts, 2011–12 dollars

Analyst	Eastern Market		Western Market	
	Present	2030	Present	2030
ACIL Tasman 2010 a	5.2	7.5	8.1	7.9
ACIL Tasman 2011 a b	5.5	10.6	-	-
ACIL Tasman 2012 a	6.0 e	11.7 e	11.2 f	11.8 f
AEMO (IES) c	5.9	8.7	-	-
DCCEE (SKM-MMA and ACIL Tasman) a	5.0	5.8	6.3	9.5
Australian Treasury 2011 (SKM-MMA) d	-	9.0	-	9.0
Australian Treasury 2011 (ROAM) d	-	9.3	-	9.3

a present refers to 2012. **b** equal weighted average of prices in table 6.3. **c** present refers to 2011.

d 2009-10 dollars. **e** weighted average of SQLG, NQLD, NSW, VIC, SA, TAS

f weighted average of SWIS and NWIS

Source: ACIL Tasman 2010b, 2011, 2012; IES 2011; SKM-MMA 2010; Treasury 2011; RET 2011

7. Conclusions

Growth in global demand for gas over the medium to longer term is expected to be robust, especially in emerging economies. Increasing global supplies of gas, particularly in terms of unconventional gas, are expected to support projected demand increases. The share of gas in the global energy mix is projected to increase, with greater consumption in electricity generation, commercial and residential sectors. The biggest growth in gas consumption will occur in rapidly growing economies with high levels of energy consumption, such as China. To meet the additional projected demand in gas importing countries, LNG-based supplies are expected to provide an increasing share of the global gas trade over the coming decade.

In Australia, both domestic consumption and exports are projected to underpin increased production. A transition to an internationally linked gas market has occurred in the Western and Northern markets and increased gas production over the past decade. A similar transition is set to occur in the Eastern market over the medium term, with the completion of three CSG LNG projects near Gladstone, Queensland.

There is an ongoing debate regarding the adequacy of future domestic production in the Eastern market to meet both domestic demand and export contracts over the short to medium term. While the commencement of exports from the three LNG facilities at Gladstone are underpinned by incremental increases in production with the development of CSG reserves, unexpected delays due to flooding and other factors may result in a temporary tightening of the Eastern market. In this event, a proportion of gas supplies that would otherwise have been available in the domestic market may not be accessible as these supplies may have been contracted to export markets. While a tightening gas market is likely in the short to medium term, increased access to international markets and higher gas prices are likely to encourage the further development of reserves and increase production over the medium to longer term.

Eastern market gas prices are projected to rise over the short to medium term, due to export demand for gas and temporary supply constraints. Over the next five years a large proportion of relatively low-priced long-term wholesale contracts will expire, with purchasers seeking to renegotiate future supply. Coincidentally, the ramp-up of gas supplies, to support the CSG-LNG facilities under construction at Gladstone, has been delayed. This has resulted in increased supply uncertainty. In turn, this has placed upward pressure on wholesale gas contract prices, with some purchasers reporting difficulties to secure contracted supplies at previous market prices.

Gas consumption is relatively price inelastic and the effect of increasing gas prices on consumption is projected to differ across sectors. Retail gas prices are determined by several cost factors including wholesale costs, network charges, retail operating costs and margins. Wholesale costs currently only account for around a third of retail gas prices. Consequently, a given percentage increase in the wholesale prices will not correspond to the same percentage increase in retail prices. Responses to higher wholesale gas prices are expected to be greatest in gas intensive industries such as in the production of fertiliser and ammonia. Substantial and

prolonged price increases, however, could reduce expected investments in gas-fired electricity generation capacity.

Over the longer term, the linkage between the Eastern market and international markets and a competitive domestic gas market should support investment and, ultimately, increase production of gas in Eastern Australia.

Glossary

Coal-seam gas (CSG)

Gas found in coal seams that cannot be economically produced using conventional oil and gas industry extraction techniques. CSG is also referred to as coal seam methane (CSM) or coal bed methane (CBM).

Conventional gas

Gas that is produced using conventional oil and gas industry extraction techniques.

Demonstrated resources

Includes all gas resources where the volume, physical characteristics and energy content can be estimated with either a high or reasonable level of confidence. This includes the *proved* and *probable reserves*, and *measured* and *indicated mineral* resource categories in the JORC code.

Economic demonstrated resources (EDR)

Gas resources that can be produced using existing technologies and are viable at current market prices.

Economic resources

Gas resources that at the time of measurement could be extracted or produced at a profit after allowing for investment expenditure, either demonstrated analytically or assumed with reasonable certainty.

Estimated ultimate recovery (EUR)

The quantity of gas which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced.

Liquefied natural gas (LNG)

Gas that has been converted into liquid form by refrigeration in a liquefied natural gas plant to around -161°C for ease of storage and transport.

LNG train

A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant. The train is used to describe the facility because the gas moves through the plant as it is purified, chilled and pressurised.

Natural gas

Natural gas is primarily methane gas that has been processed to remove impurities to a required standard for consumer use. It may contain small amounts of ethane, propane, carbon dioxide and inert gases such as nitrogen. Natural gas is commercially extracted from oil fields and natural gas fields.

Netback price (LNG netback price)

The netback price can be calculated in a variety of ways, but is commonly considered to be the delivered price of a commodity less the costs of transport, processing, marketing and risk. For natural gas shipped as LNG the netback price should be based on the delivered price of the gas less the costs of marketing, liquefaction and transport.

Oil-linked gas price

Australia's price of gas exports is generally determined by a link to a basket of crude oils known as the Japan Customs-cleared Crude (JCC). Traditionally, the LNG-shipped gas price in Asia is derived by multiplying the current JCC oil price by a 'slope factor' and then adding a constant; both the slope and the constants are negotiated. To ensure both buyer and seller of the LNG are protected against significant movements in crude oil prices, the pricing formula is designed to represent an 'S' curve. That is, above and below contractually specified crude oil prices, the LNG price is tapered such that producers exposure to low prices are limited and conversely buyers are not exposed to significant increases in the oil price.

Proved reserves

Estimated quantities of gas that are reasonably certain to be recoverable in the future under existing economic and operating conditions. Proved reserves are also known as 1P reserves.

Shale gas

Gas found in shale layers that cannot be economically produced using conventional oil and gas industry extraction techniques.

Spot prices

In Australia, gas is not yet traded in the spot market in large quantities. Gas that is additional to day to day requirements is traded in the spot market generally. The spot gas price represents the opportunity cost for infrequent use of spare gas. The price of spot gas varies day to day according to: (i) whether the market is long or short for that day, which in turn is influenced by seasonal factors and (ii) the individual situations of the major gas contract holders (such as Verve Energy, Synergy, BHP Billiton, Alinta, Alcoa, etc).

Sub-economic resources

Gas resources that do not meet the conditions to be classified as *economic*. The two categories of sub-economic resources are:

- Paramarginal—gas resources that could become *economic* with a limited increase in prices or cost-reducing improvements in extraction technology.
- Submarginal—gas resources that could only become *economic* with a large increase in prices or a significant cost-reducing improvement in extraction technology.

Technically recoverable resource (TRR)

A gas resource that could be extracted using current exploration and extraction technologies, independent of whether the resource is economic.

Train

See 'LNG train'

Unconventional gas

Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry extraction techniques.

Wholesale and retail price

Wholesale price is the price a retail establishment pays for a product it will sell on to an end-user. Retail price is the price at which they sell that same item to the public/end-user. The difference between the two prices is the retail charge and the network charge. The wholesale natural gas market refers to markets where participants such as producers, regulated and unregulated utilities, traders (e.g., banks, speculators, hedge funds, and others) buy and sell natural gas for immediate or near future physical delivery, or for delivery at distance future. More on this and the nature of wholesale gas prices in Australia is discussed in the text.

References

ABS (Australian Bureau of Statistics), 2012, Consumer Price Index, Cat. No. 6401.0, Canberra, April.

ABARES (Australian Bureau of Agricultural and Resources and Sciences), 2011, Australian Energy Statistics, Canberra, June

ACIL Tasman, 2012, Fuel Cost Projections, Fuel cost inputs for DRET's electricity generation technology cost assessment project, Melbourne.

--2011a, Fuel cost projections: natural gas and coal outlook modelling for AEMO, Prepared for AEMO/DRET, Melbourne

--2011b, Modelling greenhouse gas emissions from stationary energy sources, Prepared for DCCEE, Melbourne

--2010, Preparation of Energy Market Modelling data for the Energy White paper, Supply Assumptions report, Prepared for AEMO/DRET, Melbourne

AGL, 2012, Submission to the Department of Resources, Energy and Tourism: response to the Draft Energy White Paper, North Sydney.

AEMO (Australian Energy Market Operator), 2011, GSOO (Gas Statement of Opportunities), Melbourne

AER (Australian Energy Regulator), 2011, State of the Energy market.

Treasury (Australian Government Department of the Treasury), 2011, Strong growth, low pollution: modelling a carbon price, Canberra.

BP (British Petroleum), 2011, Statistical Review of World Energy

BP (British Petroleum), 2012, Statistical Review of World Energy

BREE (Bureau of Resources and Energy Economics), 2011a, Australian Energy Projections, Dec 2011

—2011b, Major Electricity Generation Projects, November 2011

—2012a, Resources and Energy Quarterly: March Quarter, BREE, Canberra.

—2012b, Energy in Australia, BREE, Canberra.

—2012c, Mining industry major projects, May 2012.

Cheniere Energy, 2012, Corporate Presentation, January

Core Energy Group, 2012, Gas production costs, prepared for AEMO, April

EISC (Economics and Industry Standing Committee) – Legislative Assembly, Parliament of Western Australia, 2011, Inquiry into domestic gas prices, Perth.

EIA (Energy Information Administration), 2011a, International Energy Outlook, September.

—2011b, World shale gas resources: an initial assessment of 14 regions outside the United States, April.

EnergyQuest, 2012, BREE gas production cost report, confidential report to client, Adelaide

—2011, ESAA Domestic Gas Study: Stage 2, Adelaide

—2010, ESAA Domestic Gas Study: Stage 1, Adelaide

ESSA (Energy Supply Association of Australia), 2012, Submission to the Department of Resources, Energy and Tourism: response to the Draft Energy White Paper, Melbourne.

GA (Geoscience Australia) and BREE (Bureau of Resources and Energy Economics), 2012, Australian Gas Resource Assessment AERA, Canberra.

Holmes C., 2012, Diverging gas price influences: is a global gas price possible? World Gas Conference 2012, Kuala Lumpur.

IEA (International Energy Agency), 2012, Medium-term market report 2012: market trends and projections to 2017, Paris.

—2011a, World Energy Outlook, OECD/IEA, Paris

—2011b, Natural Gas Information, OECD/IEA Paris.

—2011c, World Energy Outlook: Are we entering a golden age of gas, OECD/IEA, Paris

—2011d, World energy balance, 2011 edition, OECD/IEA, Paris

—2011e, Medium-term oil and gas markets 2011, OECD/IEA, Paris

IES (Intelligent Energy Systems), 2011, Review of Fuel Costs: a report to AEMO, January.

IGUSG (International Gas Union Study Group B2), 2012, Wholesale gas price formation, World Gas Conference 2012, Kuala Lumpur.

Miyazaki K., Limam M., 2012, Will there be a two-tier LNG contract pricing mechanism in Asia? World Gas Conference 2012, Kuala Lumpur.

New South Wales (NSW) Parliament, 2012, Inquiry into coal seam gas, Legislative Council,

General Purpose Standing Committee No. 5, Sydney

Origin Energy, 2012, Submission to the Department of Resources, Energy and Tourism: response to the Draft Energy White Paper, Sydney.

Origin Energy, 2012a, Submission to the Department of Resource, Energy and Tourism: response to the Draft Energy White Paper, Sydney.

Origin Energy, 2012b, ASX/Media Release: Origin announces major gas sales agreement with GLNG, 2 May 2012, Sydney.

PetroChina, 2012, China shale gas resources exploration and development state and prospect, March.

RET (Department of Resources, Energy and Tourism), 2011, Draft Energy White Paper: Strengthening the foundations for Australia's energy future, Canberra.

Rio Tinto, 2012, Submission to the Department of Resources, Energy and Tourism: response to the Draft Energy White Paper, Melbourne.

SKM-MMA, 2011, Projections of greenhouse gas emissions for the stationary energy sector, report to DCCEE, January.

Swarthmore College Environmental Studies, 2012, Natural gas drilling in the Marcellus Shale: how hydraulic fracturing works.

Annex

Table A1: Australian LNG projects in operation, under construction or planned

Basin / Project	Investment (US\$b)	Trains	Start date	Total Capacity (Mt)
Western market				
LNG Projects in Operation				
North West Shelf	27	5		16.3
Pluto	14.9	1		4.3
Total in operation				20.6
LNG Projects in Construction				
Gorgon Trains 1 - 3	43	3	2015	15
Wheatstone / Julimar	29	2	2016	8.9
Prelude FLNG	10+	1	2016	3.6
Ichthys	34	2	2017	8.4
Total in construction				35.9
LNG Projects Planned				
Pluto 2 & 3 (additional gas required)		2		8.6
Gorgon Train 4 & 5		2		10
Wheatstone 3 - 5		3		13.4
Browse LNG		3	2017	12
Bonaparte FLNG		1	2018	2
Sunrise FLNG		1		4.1
PTTEP FLNG		1		2
Timor Sea LNG project	2.1	1		3
Total planned				55.1
Eastern market				
CSG LNG Projects in Construction				
QCLNG	20	2	2014	8.5
GLNG	16	2	2015	7.8
APLNG	14	1	2016	4.5
Total under construction				20.8
CSG LNG Projects Planned				
QCLNG Trains 3-4		2		7.8
APLNG Trains 2-4		3		13.5

