# The Geopolitics of Natural Gas

## The Geopolitics of Australian Natural Gas Development

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# THE GEOPOLITICS OF AUSTRALIAN NATURAL GAS DEVELOPMENT

BY

RONALD D. RIPPLE, PH.D.
MERVIN BOVAIRD PROFESSOR OF ENERGY BUSINESS AND FINANCE
COLLINS COLLEGE OF BUSINESS
UNIVERSITY OF TULSA

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## About the Study

Some of the most dramatic energy developments of recent years have been in the realm of natural gas. Huge quantities of unconventional U.S. shale gas are now commercially viable, changing the strategic picture for the United States by making it self-sufficient in natural gas for the foreseeable future. This development alone has reverberated throughout the globe, causing shifts in patterns of trade and leading other countries in Europe and Asia to explore their own shale gas potential. Such developments are putting pressure on longstanding arrangements, such as oil-linked gas contracts and the separate nature of North American, European, and Asian gas markets, and may lead to strategic shifts, such as the weakening of Russia's dominance in the European gas market.

Against this backdrop, the Center for Energy Studies of Rice University's Baker Institute and the Belfer Center for Science and International Affairs of Harvard University's Kennedy School launched a two-year study on the geopolitical implications of natural gas. The project brought together experts from academia and industry to explore the potential for new quantities of conventional and unconventional natural gas reaching global markets in the years ahead. The effort drew on more than 15 country experts of producer and consumer countries who assessed the prospects for gas consumption and production in the country in question, based on anticipated political, economic, and policy trends. Building on these case studies, the project formulated different scenarios and used the Rice World Gas Trade Model to assess the cumulative impact of country-specific changes on the global gas market and geopolitics more broadly.

## Study Authors

Rawi Abdelal
Luay Al Khatteeb
Govinda Avasarala
Beibei Bao
Soner Cagaptay
Charles Ebinger
Jareer Elass
Andreas Goldthau
Peter Hartley
Simon Henderson
Trevor Houser
Amy Myers Jaffe
Robert Johnston
Ken Koyama
Azzedine Layachi
Michael Levi
Steven Lewis
Suzanne Maloney
David Mares
Kenneth B. Medlock
Keily Miller
Tatiana Mitrova
Isidro Morales
Martha Brill Olcott
Meghan O'Sullivan
Ronald Ripple

## Introduction

Australia will have an impact on the geopolitics of natural gas over the next decade and beyond, no matter which scenario of the future comes to be. Australia is geographically well-positioned to continue to engage with the Asia-Pacific energy markets where more than 60% of the global trade in LNG is transacted. And it has very supportive political and business communities motivated to monetize its substantial natural resource wealth. Australia also continues to provide an alternative source of energy to the region from a mature, politically stable democracy, where energy export decisions are driven by commercial, economic motives rather than political.

Because Australia's decisions about natural gas development and marketing are driven almost exclusively by commercial considerations,[1] and there are no domestic national oil or gas companies, the natural gas available from Australia to the rest of the world, and particularly Asia, provides a counterweight to other international natural gas supply sources that may not be allocated on such purely economic, nonpolitical grounds. It is through this avenue of market-driven engagement with the rest of the world that Australia affects the geopolitics of natural gas. Australia's capacity to supply natural gas to the region on a purely commercial basis reduces the power of suppliers who would use their natural gas resources as a strategic tool for geopolitical gain.

Australia currently has 24.2 million tonnes per annum (mtpa) of LNG production capacity in operation, with an additional 61.5 mtpa under construction.[2] The seven new natural gas export-oriented LNG projects will add to the three existing export projects such that some time prior to 2020, Australia's export capacity will surpass the current 77 mtpa capacity of Qatar. Indeed, if all of these projects are completed as currently scheduled, this capacity hurdle will be cleared by Australia before 2017. While it is not likely that all schedules will

[1] The commercial focus of investment decisions in Australia is captured within the Australian Foreign Investment Policy statement where, after noting that there may be community concerns regarding foreign ownership of some Australian assets and that decisions are based on national interest, it states: "The national interest test also recognises the importance of Australia's market-based system, where companies are responsive to shareholders and where investment and sales decisions are driven by market forces rather than external strategic or non-commercial considerations. See page one of "Australia's Foreign Investment Policy," available at www.firb.gov.au/content/policy.asp?NavID=1.

[2] These projects account for 64.5% of global capacity under construction at the start of 2013, according to several editions of the LNG Business Review.

be met, there is no indication that any of the currently under construction projects is under threat of termination or of being downgraded to a lower capacity.

Australia's influence in natural gas trade has been and will continue to be important. Australia first entered the market by providing Japan an alternative source of natural gas, thus allowing it to further diversify its sources of energy supplies. Australia opened natural gas trade with China. It is also providing the proving grounds for LNG-export projects based on coal bed methane (CBM) (referred to as coal seam gas [CSG] in Australia) and for floating LNG (FLNG). However, Australian natural gas exports are not likely to be the source of significant downward pressure on prices because it is a very high-cost jurisdiction to construct and operate in.

Understanding Australia's role in the geopolitics of natural gas begins with the internal, domestic geography and physical structure of the Australian natural gas market and how these mesh with its role in international markets. Internally, the Australian natural gas markets are split into the Eastern, Western, and Northern regions; there are currently no pipeline interconnections between any of these regions. Between 1989 and 2006, Western Australia (WA) was the only exporter of natural gas, and it also hosts the majority of the new capacity currently under construction. Exports from Darwin, in the Northern Territory (NT), started in 2006, and these will be augmented when the Ichthys project (fed from offshore WA) comes on stream. And, Australian exports will be further extended across the country with the completion of coal seam gas-based export projects in Queensland.

The politics of natural gas in Australia is affected by this internal geography and complicated by the external demands for natural gas that Australia has the capacity to supply. The vast majority of natural gas in Australia (at least that deriving from conventional geology) is found offshore of WA. These resources are far from even the populated regions around Perth, which is more than 1,500 km to the south. It has been and remains uneconomic to pipe any of this gas across the empty center of the country to reach population centers in the East.

In the East, there are offshore resources to the south of Victoria in Bass Strait that have supplied that state for decades, and these are connected to the pipeline grid of the Eastern states markets (including Tasmania since 2002, via the subsea Tasmania Gas Pipeline). There are also significant resources in the Cooper Basin, which straddles the state border between

Queensland and South Australia, with these resources also connected to the transportation grid. The Cooper Basin also holds potential for shale gas, with the first commercial production occurring in late 2012. And finally, there are large coal bed methane resources in Queensland and New South Wales.

The Northern Territory has quite modest internal production and consumption of natural gas. The Darwin LNG project is supplied from offshore fields, as will be the case for the Ichthys project, currently under construction.

The natural gas industry in Australia includes relatively large domestic players like Woodside, Santos, and Origin, but also draws significant investment and operations from virtually all of the world's oil and gas majors. The natural resource project investment environment in Australia is quite friendly to foreign investment in addition to that from domestic participants. This openness brings occasional suggestions that foreign entities are buying up Australian resources for their own specific use. Much of the focus of these larger players is on very large export-oriented projects, but there is also significant activity by myriad smaller companies that have the potential to expand the onshore—domestic production developments much like what occurred in the United States with shale gas.

Some concern has been expressed with respect to the potential for the allocation of these natural gas resources to be distorted by the influence of foreign equity ownership in the projects currently under construction. That is, there is concern that some of the gas may be directed to an equity owner's country irrespective of the otherwise "best" market for the gas. However, it should be noted that the natural gas markets targeted by the Australian export projects do not appear to be constrained or overly influenced by project equity ownership. The majority of the equity in the seven projects currently under construction is held by major international or Australian domestic oil and gas companies; all are driven primarily by economics and not politics. If there is a tendency toward concentration in any one export market it is still that of Japan, but this is to be expected since Japan remains the world's largest importer of LNG. A range of Japanese importers are equity holders in a number of the new projects, but the exports from these projects are not limited to Japan. The role of Chinese oil and gas companies in the equity stakes of the new projects is concentrated in the Queensland coal bed methane projects, which tend to be smaller than those in the West. Nevertheless, Chinese importers have also signed on for long-term volumes from new projects in the West, while some volumes from their Eastern projects are contracted to other Asian countries. Given this non-restrictive, relative equity position, Australian natural gas is also not employed geopolitically by foreign entities, even those that are state-owned.

This study finds that Australia's vast resources, relatively small domestic market, stable government, and open investment environment will lead to further building on its solid foundation for engagement with the international markets for natural gas. Australia's domestic energy policies focused on pricing carbon[3] and enhanced contributions from renewable generation technologies are expected to lead to expansion of the domestic use of natural gas, which will bring these uses into closer contact with the international pricing for natural gas, which in the Asian region is currently tied to the price of crude oil.

## Background

The primary geopolitical relevance of Australian natural gas is in its role as an exporter of the commodity to the large and growing East Asian markets.[4] The current and future volumes represent supplies from a mature, politically stable democracy that provides a counterweight to reliance on Middle Eastern, Russian, and African sources. From a geo-economic standpoint, it represents a stable source of supply that is relatively close to these markets. Moreover, Australia's export activity has always been driven primarily by economics and little influenced by international politics.

Australia's engagement with the LNG world, and the Asian portion of that world in particular, is primarily driven by economics. This is evident from the fact that virtually all of the natural gas export project investment in Australia comes from commercially driven companies, whether or not they may be state-owned in some other country. Nevertheless, Australia's current growth and potential to further expand export capacity into the region may have implications for the geopolitics of the region, and even between Australia and some of its closest allies.

[3] As discussed elsewhere, the new commonwealth government of Australia has submitted legislation to remove both the current tax on $CO_2$ emissions and the planned cap-and-trade system to follow. Nevertheless, it also has proposed policies that will stimulate the use of natural gas.

[4] Australia shows small quantities of imported natural gas, which is credited to Timor Leste (East Timor) and is natural gas produced in the joint production zone supplying the Darwin LNG facilities. These volumes, for the most part, are liquefied and shipped overseas. There are no pipeline links to foreign producers, and there are no LNG receiving terminals.

If Australia is able to further expand its capacity to export to the Asian region, at prices that provide solid returns on investment with oil-based linkages or competitively against alternative suppliers in a de-linked environment, it may slow the progress of Russian expansion into the Asia natural gas business. While Australia may be viewed from within the region as a Western force, its LNG projects have a solid reputation for reliability of supply, which to date may be considered to be superior to Russia. Moreover, since the Australian government has never intervened or interfered with the supply of LNG to any country, there will be little concern about such potential in the future. This cannot be said for Russia, and there could also be concerns in Asia, especially from China in this regard with respect to the United States.

With supplies of LNG drawn from Australian projects, it is possible for an importing country to effectively diversify sources of supply without having to consider the country of origin in the diversification decision. The projects in Australia are commercially driven by major international, commercially motivated companies, which are in virtually constant competition around the globe, even though they may also form joint ventures with these very same competitors. The joint ventures are primarily for the diversification of risk rather than with any intention to monopolize a market or region.

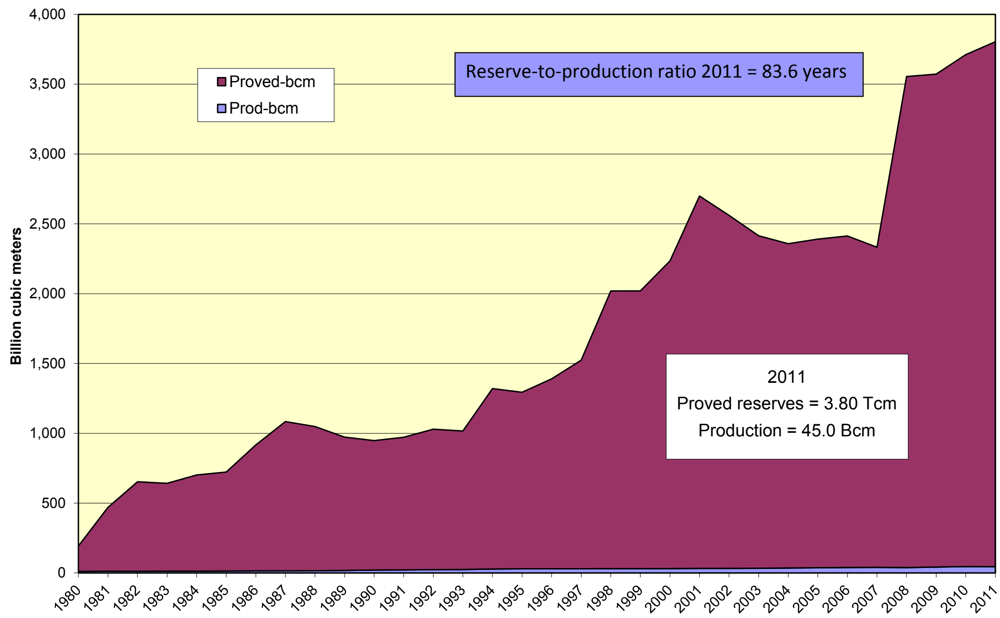
An interesting question, which cannot be fully answered here, is how does each of the LNG importing countries in the Asia region view Australia geopolitically with respect to LNG? Is Australia seen by them as simply a commercially motivated supplier of a primary energy resource, or is there a deeper concern that Australia could decide to take active steps to manipulate the natural gas export market for political gain, for example, potentially joining with the US and Canada to form a Western block of LNG supplies that could be used to bring international political pressure on countries of the region?

While such geopolitical calculations surely go on somewhere within the national security apparatus of virtually all of the countries in the region, there is no evidence, observed through actions, that such calculations have played any role in decisions by private and state-owned companies of the region regarding engagement with the Australian export-focused projects. For these reasons it is necessary to understand the current and future domestic policy and cost structure of Australia's natural gas industry to ascertain its potential to influence the geopolitics of natural gas regionally and globally.

Understanding Australia's role, and its potential, requires understanding (1) the extent of the natural gas resource base, (2) the location of the resources within Australia, (3) the level of investment in the capacity to export, (4) the shipping distances to existing and potential markets—both absolute and relative to existing and potential competitors, and (5) what the domestic demand for the resource is and will be.

The opportunity for Australia to play a significant role in the global trade of natural gas is made clear by the following graph.

**Figure 1. Australia's proved reserves and production volume of natural gas, 1980–2011**




Source: BP Statistical Review of World Energy, 2012

One may be excused for missing the thin blue area just above the horizontal axis, which reports the annual production of natural gas. The production values represent both domestic consumption and export volumes. This amounted to 45.0 billion cubic meters (bcm) (1.6 trillion cubic feet [tcf]) for 2011 against proved reserves of 3.8 trillion cubic meters (tcm) (134 tcf). In addition to the domestic production, Australia reports imports of natural gas piped to the Darwin LNG facility from the offshore Joint Production Zone in the Timor Sea; these import volumes amounted to 6.3 bcm for 2011. The combined domestic production and imports supported domestic consumption and exports of just over 51 bcm (1.8 tcf), divided roughly evenly between the two activities.

The proved reserves estimates reported in Figure 1 include coal seam gas in the Eastern states of Queensland and New South Wales, but do not include estimates of other unconventional reserves, like shale and tight gas. Indeed, much of the steep increases reported in recent years are dominated by the conversion of coal seam gas resources into proved reserves aimed at supporting the LNG facilities under construction in Queensland. Prior to these developments there were reserves declines as older conventional fields produced more than was replaced, as well as due to reallocations of reserves ownership between Australia and Timor Leste related to the offshore Joint Petroleum Development Area in the Timor Sea.

The majority of the conventional proved reserves in Australia are located in the region to the north and northwest of Western Australia; see the dark blue wedges in Figure 2. The Carnarvon Basin is the source for the two currently operating LNG facilities in Western Australia (North West Shelf Project and Pluto Project), and it is the source for two other LNG projects currently under construction (Gorgon and Wheatstone).[5] In addition to the Carnarvon Basin, there are also the offshore Browse and Bonaparte Basins. The Bonaparte Basin straddles the offshore regions of WA and NT, and the Bayu-Undan field within the Joint Petroleum Development Area supplies the natural gas feed for the Darwin LNG plant. The Ichthys project, also to be developed in Darwin, will source its natural gas feed from the Ichthys field within the Browse Basin offshore WA. Nearly all of these conventional reserves in WA are found offshore, some in relatively deep water. Hence, these are not low-cost natural gas resources, nor are the projects that will exploit them.

An apparent balance in Australia's resource bases between the West and the East is observed when CSG and other unconventional resource estimates are combined with the known conventional resources. Eastern Australia is endowed with significant CSG resources, which are estimated to exceed the West's conventional resources but are less than the West's other unconventional resources.

[5] Chevron has reported 21 discoveries in the basin since 2009 amounting to 10 Tcf of recoverable resources.

**Figure 2. Estimated conventional and unconventional natural gas resources**


Source: Santos. See footnote 7.

Figure 2[6] reports estimates compiled by Santos of combined conventional and unconventional natural gas resources, and it delineates the proven natural gas basins across Australia.[7] To date there has been relatively little exploration aimed at the unconventional resources other than CSG believed to exist in several of these basins, but exploration efforts are on the rise. Limited shale gas production has begun only recently with flows reported by Santos from its Moomba-191 vertical well in the Cooper Basin in late 2012. However, Australia is expected to hold significant shale gas resources beyond the Cooper.

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[6] According to the Santos conversion calculator (http://www.santos.com/UserControls/ConversionCalculators/ConversionCalculator.html), 1 petajoule (PJ) = 0.9430 Bcf. Hence, for the Western Australia basins there is estimated to be 448.5 Tcf of conventional and unconventional natural gas resources.

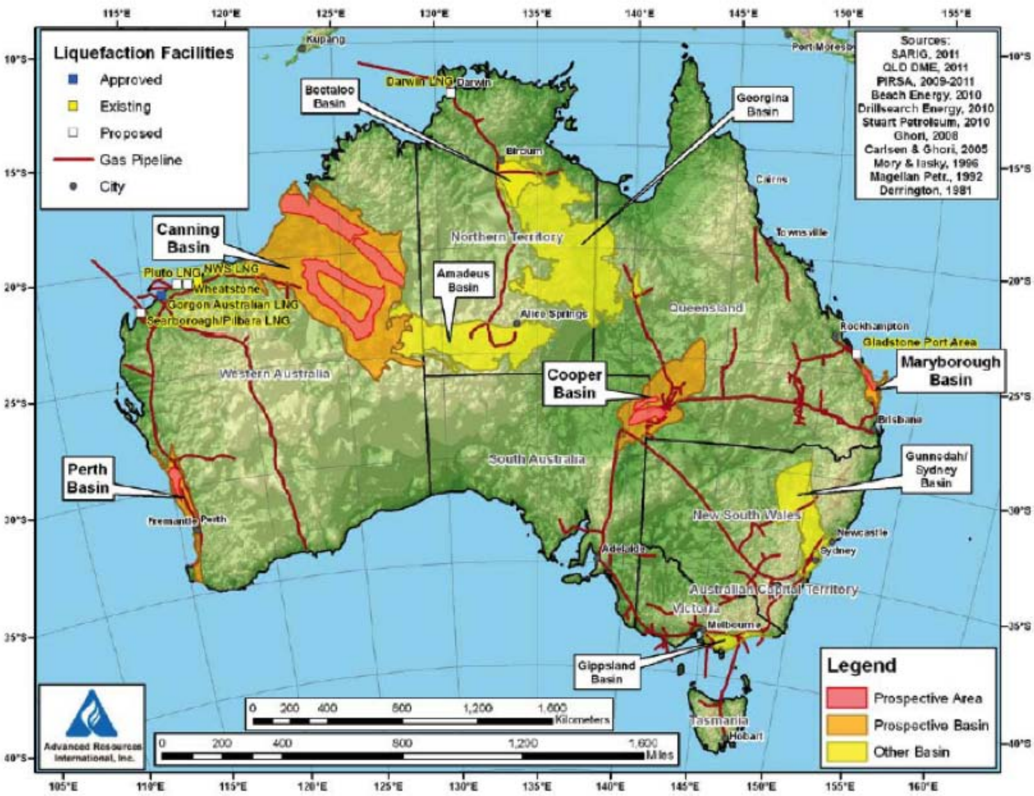
[7] Additional sedimentary basins exist that have not been well explored to date. These include the Great Australia Bight to the south of South Australia in commonwealth waters and Lord Howe Rise in the Tasman Sea east of Australia. Exploration permits have been granted to BP, Chevron, Murphy, and Santos for the Great Australian Bight.

An EIA (2013) study[8] estimates Australia to have the seventh largest potential shale gas resource with 437 tcf (this is up from the 396 tcf estimated in the EIA's 2011 study) of risked recoverable resources. The additional reserves that will be supported by this resource base will further enhance Australia's ability to provide continuing alternative sources of natural gas to the region and the world. Figure 3 and Table 1, drawn from the EIA report, provide estimates of shale gas potential, the locations, and the natural gas transportation pipelines in Australia, which reveal the lack of regional interconnection. Unlike much of the shale gas resource finds in the US, the Australian shale gas tends to be remote from population centers, and only those in the Cooper Basin can currently be readily delivered into an existing pipeline system. Table 1 (panel 2) reveals that the largest potential shale gas resource is in the Canning Basin in Western Australia; however, it is very remote even by WA standards.[9]

[8] See *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, EIA/ARI, 2013. This is a follow-up to *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, EIA/ARI, 2011. It should be noted that even though the 2013 study expanded the number of basins assessed, it still did not examine all potential shale formations in Australia. Indeed, Geoscience Australia states that Australia is relatively under-explored by international standards, so some additional expansion of the resource estimates may be expected.

[9] Nevertheless, while the Canning Basin is remote from domestic WA end-users, it is relatively near existing, under construction, and planned LNG facilities in the northwest of WA and may therefore be a prospective feed source to augment conventional natural gas supplies or to replace depleted reserves.

**Figure 3. Australia's prospective gas shale basins, gas pipelines, and LNG infrastructure**




Source: Energy Information Administration

Active exploration operations are underway in the Cooper Basin[10] led by Santos and Beach Energy, and in the Canning Basin where Buru Energy has been joined by ConocoPhillips. Several other independent exploration efforts are underway in the Cooper, Canning, and Perth Basins.

[10] The recent news of commercial shale gas production beginning in Australia from the Cooper Basin in South Australia set many to speak of game-changing developments. However, the news remains mixed. While the Santos Moomba-191 well is producing and delivering gas into the eastern pipeline system, recent flow rates cited by Beach Energy at its Moonta-1 vertical well, also in the Cooper Basin, were regarded in the media as relatively low. However, these wells are vertical fractures, which are expected to produce lower initial controlled flow rates. Chevron appears to have been undaunted by media concerns and joined Beach by putting up US$349 million to support the drilling program and acquire up to 60% of Beach's interest in two blocks.

## Table 1. Australia's shale resources

Panel 1.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Cooper (46,900 mi$^2$) | | | | | | |
| | Shale Formation | | Roseneath-Epsilon-Murteree (Nappamerri) | | | Roseneath-Epsilon-Murteree (Patchawarra) | | | Roseneath-Epsilon-Murteree (Tenappera) |
| | Geologic Age | | Permian | | | Permian | | | Permian |
| | Depositional Environment | | Lacustrine | | | Lacustrine | | | Lacustrine |
| Physical Extent | Prospective Area (mi$^2$) | | 625 | 555 | 3,525 | 1,010 | 1,150 | 170 | 200 |
| | Thickness (ft) | Organically Rich | 250 | 500 | 500 | 125 | 100 | 100 | 225 |
| | | Net | 150 | 300 | 300 | 75 | 60 | 60 | 135 |
| | Depth (ft) | Interval | 5,000 - 7,000 | 6,000 - 10,000 | 7,000 - 13,000 | 7,000 - 9,200 | 8,000 - 10,000 | 8,000 - 13,000 | 5,000 - 6,500 |
| | | Average | 6,000 | 8,000 | 10,000 | 8,000 | 9,000 | 10,500 | 5,500 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Normal | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 2.6% | 2.6% | 2.6% | 2.6% | 2.6% | 2.6% | 2.6% |
| | Thermal Maturity (% Ro) | | 0.85% | 1.15% | 2.00% | 0.85% | 1.15% | 1.30% | 0.85% |
| | Clay Content | | Low | Low | Low | Low | Low | Low | Low |
| Resource | Gas Phase | | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas |
| | GIP Concentration (Bcf/mi$^2$) | | 13.1 | 87.6 | 100.1 | 7.3 | 15.6 | 18.6 | 10.1 |
| | Risked GIP (Tcf) | | 6.1 | 36.5 | 264.7 | 4.4 | 10.8 | 1.9 | 1.2 |
| | Risked Recoverable (Tcf) | | 0.7 | 9.1 | 79.4 | 0.4 | 2.7 | 0.5 | 0.1 |

Source: Technically Recoverable Shale Oil and Shale Gas Resources, 2013

Panel 2.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Maryborough (4,290 mi$^2$) | Perth (20,000 mi$^2$) | | | Canning (181,000 mi$^2$) | | |
| | Shale Formation | | Goodwood/Cherwell Mudstone | Carynginia | Kockatea | | Goldwyer | | |
| | Geologic Age | | Cretaceous | U. Permian | L. Triassic | | M. Ordovician | | |
| | Depositional Environment | | Marine | Marine | Marine | | Marine | | |
| Physical Extent | Prospective Area (mi$^2$) | | 1,540 | 2,200 | 860 | 1,030 | 14,900 | 19,620 | 22,860 |
| | Thickness (ft) | Organically Rich | 1,250 | 950 | 300 | 300 | 1,000 | 1,300 | 1,300 |
| | | Net | 250 | 250 | 160 | 160 | 250 | 250 | 250 |
| | Depth (ft) | Interval | 5,000 - 16,500 | 3,300 - 16,500 | 3,300 - 15,100 | 9,200 - 16,500 | 3,300 - 7,200 | 7,200 - 10,500 | 10,500 - 16,500 |
| | | Average | 9,500 | 10,000 | 9,200 | 11,000 | 5,200 | 8,800 | 13,500 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Normal | Normal | Normal | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 2.0% | 4.0% | 5.6% | 5.6% | 3.0% | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 1.50% | 1.40% | 0.85% | 1.15% | 0.85% | 1.15% | 1.40% |
| | Clay Content | | Low | Low | Low | Low | Low | Low | Low |
| Resource | Gas Phase | | Dry Gas | Dry Gas | Assoc. Gas | Wet Gas | Assoc. Gas | Wet Gas | Dry Gas |
| | GIP Concentration (Bcf/mi$^2$) | | 110.7 | 94.0 | 14.0 | 58.9 | 18.7 | 67.1 | 109.2 |
| | Risked GIP (Tcf) | | 63.9 | 124.1 | 7.2 | 36.4 | 83.5 | 395.0 | 748.7 |
| | Risked Recoverable (Tcf) | | 19.2 | 24.8 | 0.6 | 7.3 | 6.7 | 79.0 | 149.7 |

Source: Technically Recoverable Shale Oil and Shale Gas Resources, 2013

Panel 3.

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Georgina (125,000 $mi^2$) | | | | | Beetaloo (14,000 $mi^2$) | | | | | |
| | Shale Formation | | L. Arthur Shale (Dulcie Trough) | | L. Arthur Shale (Toko Trough) | | | M. Velkerri Shale | | | L. Kyalla Shale | | |
| | Geologic Age | | M. Cambrian | | M. Cambrian | | | Precambrian | | | Precambrian | | |
| | Depositional Environment | | Marine | | Marine | | | Marine | | | Marine | | |
| Physical Extent | Prospective Area ($mi^2$) | | 2,260 | 1,950 | 3,220 | 2,010 | 790 | 2,650 | 2,130 | 2,480 | 4,010 | 2,400 | 1,310 |
| | Thickness (ft) | Organically Rich | 115 | 115 | 65 | 65 | 65 | 450 | 450 | 450 | 520 | 520 | 520 |
| | | Net | 85 | 85 | 50 | 50 | 50 | 100 | 100 | 100 | 130 | 130 | 130 |
| | Depth (ft) | Interval | 7,200 - 10,500 | 2,300 - 3,300 | 3,300 - 4,000 | 4,000 - 5,000 | 5,000 - 6,500 | 3,300 - 5,000 | 5,000 - 7,000 | 7,000 - 8,700 | 3,300 - 5,000 | 5,000 - 6,000 | 6,000 - 8,000 |
| | | Average | 8,800 | 3,000 | 3,600 | 4,500 | 5,700 | 4,200 | 6,000 | 7,500 | 4,200 | 5,500 | 6,500 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal | Normal | Normal | Normal | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. |
| | Average TOC (wt. %) | | 3.0% | 5.5% | 5.5% | 5.5% | 5.5% | 4.0% | 4.0% | 4.0% | 2.5% | 2.5% | 2.5% |
| | Thermal Maturity (% Ro) | | 1.15% | 1.50% | 0.85% | 1.15% | 1.50% | 0.85% | 1.15% | 1.60% | 0.85% | 1.15% | 1.60% |
| | Clay Content | | Low | Low | Low | Low | Low | Low | Low | Low | Low | Low | Low |
| Resource | Gas Phase | | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas |
| | GIP Concentration (Bcf/$mi^2$) | | 22.8 | 29.1 | 4.5 | 17.5 | 26.7 | 7.2 | 30.7 | 42.0 | 11.7 | 37.1 | 49.6 |
| | Risked GIP (Tcf) | | 19.3 | 21.3 | 5.5 | 13.2 | 7.9 | 9.6 | 32.7 | 52.0 | 23.5 | 44.5 | 32.5 |
| | Risked Recoverable (Tcf) | | 3.9 | 4.3 | 0.4 | 2.6 | 1.6 | 1.0 | 8.2 | 13.0 | 2.3 | 11.1 | 8.1 |

Source: Technically Recoverable Shale Oil and Shale Gas Resources, 2013

Australia became a player in the trade of natural gas when it first entered the export trade sector with the completion and first shipments of LNG from the North West Shelf (NWS) project in 1989. This provided an alternative source of natural gas supplies to Japan, and it has proved to be a stable, reliable supplier ever since. The NWS project was developed by a consortium led by Australia's Woodside Petroleum, and joined by Shell, Chevron, BHP, Mitsubishi/Mitsui, and BP, all as equal partners. The project has a record of reliable supply to its customer base, which is primarily in Japan.

After proving itself in the market, Australia forged the first deal to supply natural gas for import into China. This initial deal laid the foundation for entry into the largest energy using economy in the world. In addition to being the first into China, investments in the Australian natural gas export sector are also destined to bring two other world firsts to the trade in natural gas. The first of these will be LNG production fed from coal bed methane, with the Queensland projects leading the way. The second first will be the commercial development, production, and delivery of natural gas by a floating LNG system.[11] The commercialization

[11] Shell "cut first steel" (October 18, 2012) in South Korea to build the first FLNG system. This floater will be brought to offshore Western Australia for installation over the Prelude field where Shell has been joined by Inpex. The Prelude field is about 200 km from nearest landfall, but the resource is not deemed large enough to justify a land-based LNG production facility and the attendant subsea investment.

The planned Bonaparte FLNG also recently (October 25, 2012) received environmental approvals. The project is a joint venture between GDF Suez and Santos, and it will be based about 250 km west of Darwin, with planned capacity of 2 mtpa. FID is expected in 2014 with first production in 2018.

of these technological developments holds out the potential to significantly increase the economically recoverable natural gas resource base around the world that for many years was viewed as stranded.

In addition to these firsts, the Chevron-led Gorgon LNG project will include the world's largest carbon dioxide injection and sequestration facilities, sequestering 3.5 mtpa of CO2 deep below Barrow Island, offshore in WA. This system recently has been reported to add approximately $2 billion to the project's price tag.[12] So while Australia joined a relatively small group of LNG exporters in 1989, it has shown that it can take the lead and forge ahead of the rest of the pack in the development of markets and the implementation of new technology. This is now being further revealed with the massive liquefaction and export capacity expansions underway.

Table 2 provides a list of Australian LNG projects, including the three currently operating, the seven under construction, and a selection of other planned projects. The dates represent current planned start dates and capacities, as well as planned capacity expansions.

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Also, the sponsors of the Browse project announced that they will examine the economic viability of monetizing their offshore natural gas via an FLNG project almost immediately after terminating plans for the land-based project at James Price Point, north of Broome.

[12] See, for example, "World's largest carbon capture begins even as Abbott tax repeal looms," *Sydney Morning Herald*, September 11, 2013.

**Table 2.**

**Australian LNG Projects: Operating, Under Construction, and Planned (capacities - mtpa)**

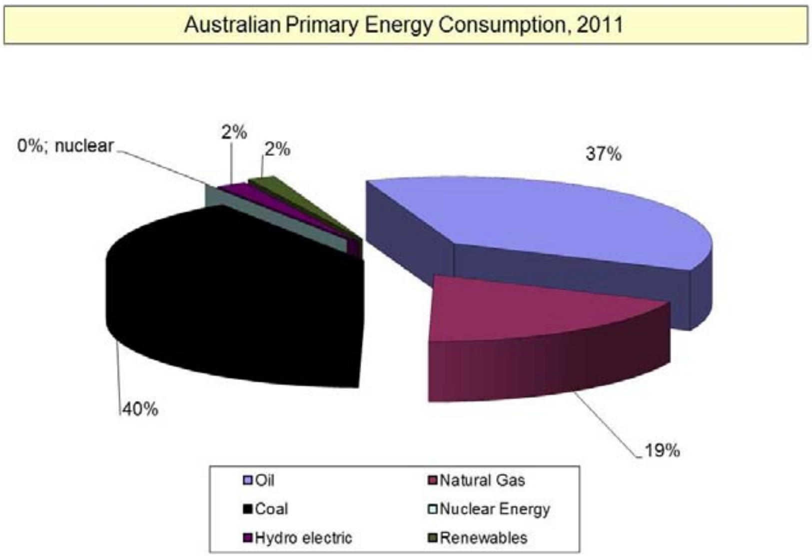
| Project | Year 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| NWS | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 |
| Darwin | 3.6 | 3.6 | 3.6 | 3.6 | 3.6 | 3.6 | 3.6 | 3.6 | 3.6 |
| Pluto | 4.3 | 4.3 | 4.3 | 4.3 | 4.3 | 8.6 | 12.9 | 12.9 | 12.9 |
| Gorgon | | | 15.0 | 15.0 | 15.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| QCLNG* | | | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 |
| GLNG* | | | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| APLNG* | | | | 4.5 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 |
| Fisherman's* | | | | 1.9 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 |
| Wheatstone | | | | | 8.6 | 8.6 | 8.6 | 8.6 | 8.6 |
| Ichthys | | | | | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 |
| Prelude** | | | | | | 3.6 | 3.6 | 3.6 | 3.6 |
| Sunrise** | | | | | | 4.0 | 4.0 | 4.0 | 4.0 |
| Browse | | | | | | 12.0 | 12.0 | 12.0 | 12.0 |
| Arrow LNG* | | | | | | 4.0 | 8.0 | 8.0 | 8.0 |
| Boneparte** | | | | | | 2.0 | 2.0 | 2.0 | 2.0 |
| Total | 24.2 | 24.2 | 55.5 | 61.9 | 85.3 | 120.2 | 128.5 | 128.5 | 128.5 |

Operating    Under construction    * - CSG-LNG    ** - FLNG

Source: LNG Business Review

These seven projects together represent nearly $190 billion of investment by an array of international and domestic oil and gas companies in production and export capacity that will propel Australia past Qatar as the largest exporter of LNG in the world. While the "crown" may pass back to Qatar at some point in the future, since Qatar has implemented a moratorium on further developments of it natural gas resources until at least 2015, it is likely that Australia will carry the largest export capacity into the 2020s. Australia has risen from being a relatively small player from a distant and remote part of the world to ranking among the top exporters of LNG and growing to be the number one supplier as we progress toward 2020. These developments, while facilitated by supportive governments, have been driven through the actions and investments of private sector participants.

**Figure 4.**




Source: BP Statistical Review of World Energy, 2012

Australian domestic natural gas demand is complex, and there are undercurrents of discontent from domestic consumers—current and potential. Figure 4 shows that for 2011, natural gas consumption in Australia accounted for 19% of primary energy consumption. Australian domestic demand is expected to increase significantly, with the Bureau of Resources and Energy Economics (BREE)[13] projecting that by 2035, natural gas will account for 35% of primary energy consumption.[14] While the existing resources should be able to handle this increased demand as well as that for exports, some frictions may arise due to infrastructure limitations and pricing. A good deal of the projected increase in domestic demand is expected to derive from electricity generation. At the time the BREE report was produced, it was expected that the newly imposed CO2 emissions tax would tend to raise the cost of coal-fired generation—Australia's primary source of electricity. Nevertheless, even with the change in government and the likely elimination of the tax, there is still an expectation of a significant shift from coal to natural gas-based generation. The electricity generated by coal in Australia accounts for 75% of all generation.[15] Thus, the replacement of

[13] BREE is in the Department of Resources, Energy, and Tourism of the commonwealth government.
[14] See Australian Energy Projections to 2034-2035, BREE, 2012, p. 30. BREE reports that natural gas accounted for 22% of primary energy in 2008-2009, while the BP statistics report 19%. This may be due to differences in timing, with BREE on a fiscal year and BP on a calendar year.
[15] According to Energy in Australia, 2012, total generation for the 2009-2010 period was 242 terawatt hours. Placing this in context, this amounts to just over 5% of total annual generation in the US, or about 21 days worth of generation on average, where about 42% of the generation is coal-based.

a large share of this generation would significantly increase domestic demand for natural gas relative to current and past levels.

According to the BREE projections, the share of natural gas used in electricity generation will increase from 16% to 36% over the period from 2008-2009 to 2034-2035, while coal's share will decline from 74% to 38%. In overall domestic consumption, natural gas is expected to increase from 1,244 PJ in 2008-2009 to 2,611 PJ in 2034-2035.[16] However, during this same period exports are expected to increase to 5,663 PJ (107 mt or about 5.3 tcf), dwarfing domestic use.

In addition, the mandated renewable energy capacity/generation (20% by 2020) will increase the demand for natural gas generation to provide a backstop for the intermittency of the renewables. This stimulus to domestic consumption is captured in the BREE projection of natural gas' share.

The previous commonwealth government introduced a tax on CO2 emissions that became effective on July 1, 2012. The initial tax was A$23.00 per tonne of CO2 emissions, escalated annually at 2.5% over CPI inflation during the initial three years. Following this initial period, the program was scheduled to shift to a cap-and-trade mechanism. The planned trading system would initially ban the use of foreign permits to satisfy Australian requirements, but Australian permits would be available for sale on the international market. There would also be an upper and lower bound on the market price for the first five years of the trading program.[17] The Liberal-National Coalition has since been returned to government in the late 2013 elections, and it has stated that its first legislative priority is to abolish the CO2 emissions tax. However, the Coalition has agreed to the bipartisan commitment of an unconditional reduction of CO2 emissions of 5% below 2000 levels by 2020, which will tend to increase demand for natural gas to replace coal and support renewables.

[16] The projections for expanded natural gas use are based on the reasonable assumption that LNG pricing in the Asia Pacific will continue to be oil-indexed and that Australian domestic prices will adjust moderately over time to the export netback prices. That is, domestic prices will not rise to the Asian landed (oil-indexed) prices but rather will fall below such prices by the transactions costs required to ship the natural gas from Australia to the respective markets.

[17] The upper bound would be A$20 per tonne above the expected international price. The lower bound would begin at A$15 per tonne, and this would escalate at 4% per year. The initial cap for emissions during the flexible price phase was not to be set until the 2014 budget document, but the maximum level of emissions would be set to meet the unconditional reduction target of 5% below Australia's 2000 CO2 emissions levels by 2020.

## Political Trends

The political structure of Australia, at commonwealth and state levels, follows the British Westminster Parliamentary system. While the political structure in Australia is viewed as quite stable, there have been several recent changes at the commonwealth government level. The current commonwealth government was formed by the Liberal-National Coalition with Tony Abbott as prime minister (PM). Mr. Abbott's elevation to PM resulted from election victory over the Kevin Rudd-led Labor Party in late 2013, and Mr. Rudd had only recently returned as PM with the ouster of Julia Gillard, Australia's first woman prime minister.

In addition to the commonwealth government there are six states and two territories; the states are Western Australia, South Australia, Victoria, Tasmania, New South Wales, and Queensland, and then there is the Northern Territory and the Australian Capital Territory (ACT), which includes the national capital of Canberra.

Currently, four of the six states are governed by Liberal-National Coalitions[18]; these are Western Australia, New South Wales, Queensland, and Victoria. Tasmania and South Australia have Labor governments. Elections come due at varying times, with some on specific dates and others at the discretion of the government in power as long they are held prior to certain dates.[19] The Northern Territory and the ACT have legislative powers delegated to it by the commonwealth government, but these are not constitutionally prescribed. As a result, the commonwealth government can overrule legislation put forward by the Legislative Assembly. Each state also has a governor, and the commonwealth a governor-general, who are the Queen of England's representative. These are largely ceremonial positions filled by people chosen by the Australian governments of the day.

The different levels of government have implications for the approval processes that any proposed project will have to pass through. Offshore projects beyond state waters, with no land-based facilities, come under commonwealth jurisdiction. Onshore resource projects come under the jurisdiction of both the commonwealth government and the relevant state government, in which case they must pass the scrutiny of both levels of government for

[18] Queensland is governed by the Liberal National Party, which is a formal joining of the two parties.
[19] Most recently the Liberal-National coalition was returned to government in Western Australia at the March 9, 2013, election.

environmental issues.[20] Regardless of physical location, if there is significant foreign investment involved, a project must be approved by the Foreign Investment Review Board.[21] This review authority rests with the commonwealth government, which, while rare, may overrule any state's desire to see a project progress.

Australia has been faced with the same domestic concerns about the export of its natural resources as have most other resource-rich countries around the globe. There is frequently tension between supporting development of non-renewable resources primarily for export and revenue generation versus the use of the resources domestically, either in value-added processes before export or as an important input into productive processes of other domestic industrial or manufacturing operations. These types of internal, domestic tensions have resulted in the application of a domestic reservation policy for natural gas development in Western Australia.

Western Australia's domestic natural gas reservation policy is not formalized in law, but it has been carried forward by both sides of the political spectrum. The central theme of the policy is that up to 15% of the reserves developed for an export project that has WA land-based processing are to be reserved for domestic uses, even if the gas is produced from an offshore field in commonwealth jurisdiction.[22] Given Western Australia's physical isolation, this means that the reserved natural gas is for Western Australia uses only.

The government in Queensland—home to the CSG-based LNG projects—is as yet undecided on its position on a domestic gas reservation policy. However, the Northern Territory

[20] There has been the suggestion, albeit not confirmed by Shell, that the Prelude FLNG project is motivated by a desire to avoid dealing with both state and federal jurisdiction issues. However, there also seem to be relevant economics, including the WA domestic natural gas reservation policy, that do not support bringing the relatively small resources to shore compared to employing an all-offshore, floating structure.

[21] The Foreign Investment Review Board (FIRB) provides guidance to the treasurer regarding the national interest of proposed investments by foreign entities in Australian assets that have a value exceeding an annually indexed threshold value; as of January 2013 that value is A$248 million. Exceptions apply to New Zealand and United States investors, where the threshold is A$1,078 million, and for any foreign government-owned entity for which the threshold is A$0—that is, any foreign government investment proposal must seek approval regardless of the value of the asset. Clearly each of the LNG export projects well exceeds these thresholds. However, as noted in footnote 1 above, the national interest determination is primarily based on commercial considerations, and national interest is evaluated on a case-by-case basis.

[22] There is some flexibility in the application of the policy, such as allowing the obligation to be met by paying a third party to supply the required gas. However, this still represents an additional cost that must be borne by the investor. The initial application of the policy likely assisted the development of the original Northwest Shelf Project; however, in that situation the investors were guaranteed a price under take-or-pay conditions, which no long apply.

government has stated that no reservation policy will be employed, and the commonwealth government has also specifically opposed implementing such a policy.[23]

As recently as August 16, 2012,[24] the commonwealth government of Australia rejected the call for a national natural gas domestic reservation policy. This position was confirmed in the government's Final Energy White Paper, released October 2012, where it stated:

> The Australian Government does not support calls for market interventions such as a reservation policy. Such measures should be a matter of last resort, undertaken only where there is clear evidence of market failure. Currently, there is no compelling evidence to support this. (p. 134)

The domestic reservation of natural gas has an organized lobbying group called DomGas Alliance (see Box 1). The DomGas Alliance argues that no other country in the world allows its natural gas to be exported without first considering domestic needs. They also try to support their positions by arguing that the prices faced in Australia are significantly higher than those being faced in North America. Such arguments may play well with relatively uninformed domestic observers, but the position ignores significant differences between North America and Australia in terms of existing infrastructure, the proximity of resources to that infrastructure, and access to technology and skills to exploit the resource. It is not that long ago that the prices in North America exceeded those that likely will apply to Australian domestic prices under netback pricing.

[23] This opposition is in large part due to the understanding that the negative economic consequences of such a policy are logically consistent with those believed to hold for import tariffs. They both tend to reduce investment incentives and economic activity, including job creation.
[24] Prime Minister Julia Gillard stated that "[t]he government does not support recommendations in the report to further investigate … a domestic reservation policy for gas." This was in response to a report titled "Smarter Manufacturing for a Smarter Australia," from the prime minister's own Manufacturing Task Force. See http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/7986077.

**Box 1. The DomGas Alliance**

The DomGas Alliance was formed in Western Australia in 2006. The current membership includes 11 natural gas purchasing firms: Alcoa of Australia, Alinta, Burrup Fertilisers, Dampier Bunbury Pipeline, ERM Power/NewGen Power, Fortescue Metals Group, Gold Fields, Horizon Power, Newmont Australia, Synergy, and Verve Energy. These natural gas users account for roughly 80% of the Western Australia in-state (i.e., excluding exports) natural gas consumption.

The DomGas Alliance supports domestic reservation policies within Western Australia and more broadly across the country. Their position effectively argues against domestic gas being priced according to its international netback value determined through exports via LNG supply chains.

Source: http://www.DomGas.com.au/index.html

The significant fall in prices in North America is commonly associated with the rapid and massive development of shale gas. The production of these well-known but previously sub-economic resources followed technological breakthroughs that were stimulated in large part by the market-based high prices that previously existed. This price-motivated, technology-driven structural change was enhanced by a combination of resource ownership characteristics and proximity to existing transportation infrastructure that does not apply in Australia.

Queensland's rapid expansion of its CSG resources was similarly motivated by prices. The resource has been known to exist for a long time, and the technology to develop it is not new. Nevertheless, until there was deemed to be an export market for the gas, at international netback prices, the resource was not commercially viable at prevailing domestic prices and quantities. The relatively small size of the domestic market, even with projected growth and Eastern states' pipeline interconnectivity, is not sufficient to produce the necessary returns on investment that would attract such investment. So for Queensland, the increased volumes of natural gas are not due so much to technology, but rather to the pull of international market prices. It is important to understand that the same volumes that are now expected to be produced would not be produced if it were not for the export prices to be obtained. As a result there would be less economic activity, lower tax revenues, and fewer jobs.

North America is characterized by the most highly integrated natural gas pipeline system in the world, and this is further supported with substantial integrated natural gas storage capacity. Australia has nothing approaching this level of infrastructure flexibility, therefore it is not meaningful to compare current or previous North American natural gas market prices with current Australian natural gas market prices.[25] Moreover, the initial North American shale gas development was driven by relatively high domestic prices; it likely would not have occurred had domestic prices been artificially low. Indeed, the US experience of the 1970s with government-mandated, artificially low prices for natural gas led to shortages of supplies even for gas sourced from conventional geology.

The desire to restrict some volume of natural gas production for domestic consumption—primarily for industrial use—does not appear to go hand-in-hand with a desire to block exports, generally. In fact, many of the DomGas participants appear to desire what amount to subsidized prices so that they may remain competitive in their own export markets. In the end, what the DomGas parties are interested in is lower prices with some assurances of supply availability. While they seem to realize that they are relatively small purchasers compared with the foreign importers, they do not want to be treated as solely residual buyers who get what is left over. They desire to be treated as being as important as the foreign purchasers—even while they strenuously argue for lower prices than those that represent competitive pricing relative to the export opportunity cost to the producers and/or the cost they would face for such supplies if the export markets did not exist.

However, there is more than one opportunity cost involved. The opportunity cost to the suppliers of the gas is the netback price they can receive by exporting. The opportunity cost to the DomGas consumers is what they would have to pay for the same input service but by

[25] It is also worth noting that the significant downward pressure and movement of natural gas prices in North America has led to a shifting of investment away from natural-gas-only plays to those that are liquids rich. This has resulted in increases in natural gas prices even without exports. However, it seems likely that when US natural gas exports are allowed investment will quickly respond to any increase in price, thus bringing more supply to support both domestic and export markets with modest impact on prices. Exactly how this modest upward pressure on US prices will be felt in the Asian natural gas markets, and thus on netback prices to Australia, is yet to be determined and will depend on a combination of how significant a share of the Asian LNG volumes the US exports represent and to the ability of existing suppliers to withstand calls for de-linking LNG and crude oil prices.

using an alternative to natural gas. While the cost of the alternative could be such that it would put the user out of business, there is still no justification/incentive for the producer/exporter to sell volumes at prices below its opportunity cost. To do so would be to subsidize the DomGas user, and subsidies are the purview of governments. If the government, which owns the resource in Australia, deems it appropriate to subsidize DomGas users, it should do so. However, it would be effectively confiscatory for the government to require the private producer/exporter to provide the subsidy. The government has the option of employing some of its royalty and tax receipts to subsidize the DomGas activities, or it may take its royalty share in-kind and simply provide those volumes to the DomGas sector at a price that conveys the level of subsidy deemed appropriate.

Even with these internal debates, the development of natural gas and other primary resources is well supported by the two main political factions in Australia. Each side of government appears to support the development of natural gas for both domestic and export purposes. Neither of the major parties appears to support the imposition of a domestic reservation policy at the national level, and they fundamentally accept that the market will appropriately allocate the developed resources, with appropriate regulatory oversight. Their primary motivation appears to be based on economics (revenues and jobs) not geopolitics. In other words, Australia's development of natural gas export projects is not viewed through a prism of how such development may be used to influence international political debate or issues across the region. But as noted earlier, Australia's ability to export may have the effect of limiting geopolitical manipulation by others.

As noted above, each of the states and the commonwealth have imposed renewable energy policy targets, which will tend to decrease the use of coal and likely enhance the demand for natural gas to support the intermittency of the renewables. These targets should lead to greater domestic demand for natural gas and hence more pressure to explore, develop, and produce more natural gas into the future. However, the prices that may result for the domestic markets are as yet uncertain.

**Political Analysis**

Both sides of politics see significant economic value to developing the country's natural gas resources, as long as this can proceed in an environmentally sensible way. These developments are seen to be generally in the national interest. Hence, the changes in government that resulted from the recent elections are not expected to lead to any significant change in policy toward the development and export of natural gas. Such developments are seen as another element of enhancing Australia's role within the Asia-Pacific economy, and to a much lesser extent to potentially enhance influence within regional political spheres.

Both sides of politics also see natural gas development, for both domestic and export use, providing positive environmental dividends regardless of their different approaches to responding to the climate change debate. Indeed, sales of natural gas into Asia is frequently discussed in terms of its relatively low environmental impact and its potential to positively impact on regional emissions through substitution for coal burning.

The Abbott government proposed a direct action policy, which focuses on providing financial incentives to industry and agriculture to invest in CO2 emissions reduction technologies, including increased use of natural gas, and for households to invest in home insulation.

The recent change of government will not change Australia's commitment to a minimum level of CO2-e reduction. Each of the two primary sides of politics have agreed to a minimum CO2-e reduction, unconditional on what the rest of the world may do, of 5% below 2000 emissions levels by 2020. If the rest of the world can come together with a unified plan to reduce emissions, Australia will then increase its level of reduction accordingly. Just as with the Gillard government programs, the Abbott direct action policy is also aimed at meeting this target. Therefore, there is not likely to be any significant change to the domestic use of natural gas, as its use is seen by both sides as supporting renewables and assisting in meeting the lower emissions target. And natural gas exports will continue to be driven by economic considerations.

On the environmental front, the Australian Greens appear to have lost much of the influence they wielded as part of the Gillard government; in the earlier election they pulled roughly 12% of the electorate and joined with the Australian Labor Party to form the minority government in 2010. In the recent 2013 elections their support fell to 8.6%, and they lost their position of holding the balance of power in the Senate. The Greens influence was felt through the carbon pricing mechanism, renewables requirements, and support for significant

R&D in clean energy sources; however, much of this policy focus had been part of the previous Rudd government policy. One area of discord that existed between the Greens and Labor was related to coal, where the Greens' stance amounts to a total end to coal, while Labor supports continued production, export, and domestic use enhanced by carbon capture and storage technologies. Natural gas developments find relatively broad support from the major political parties, but less so from the Greens and other environmental groups.

In the Eastern states where CSG/CBM developments are expanding rapidly, some groups, such as one known as Lock-the-Gate, oppose the development of these natural gas resources, raising questions about environmental damage from poor handling of produced water and interference with surface activities of land owners.[26] This latter issue is exacerbated by the characteristics of land and sub-surface resource ownership in Australia. The sub-surface resources in Australia belong to the government, and rights to explore for and develop these resources are allocated by the government. Initially the very rapid development of CSG/CBM reserves in Queensland led to frictions between surface land owners and resource developers because there often was little or no consultation with owners of the surface rights. This has been largely mitigated, with better communication and reasonable compensation and cooperation between the parties now more typical.

In Queensland, policies, procedures, and regulations were re-examined and strengthened to ensure that environmental concerns, particularly regarding water quality, were appropriately addressed.[27] The opposition to these natural gas developments appears to have operated as a motivator for governments to ensure that appropriate regulations and enforcement were in place for technologies that appeared unfamiliar to the general community. However, it does not appear that the opposition will permanently block development in any region of the country.

[26] While hydraulic fracturing is frequently introduced into the debates, relatively few CSG/CBM wells have been hydraulically fractured, see for example, Drilling down. Coal Seam Gas: A background paper, p. 4, a report by the Institute for Sustainable Futures, University of Technology Sydney, November 2011, available for download at cfsites1.uts.edu.au/find/isf/publications/rutovitzetal2011sydneycoalseamgasbkgd.pdf. There seems to be an unfortunate conflation of issues raised in association with hydraulic fracturing in shale gas development with those of produced water handling associated with coal seam gas production.

[27] Examples of Queensland's measures, which focus on CSG development, are the ban on open pit evaporation ponds for produced water, unless no other option is available. The first priority is aquifer injection or virtual (replacement of otherwise groundwater draw down) injection of suitably treated water, and the second priority is beneficial use of produced water (treated, used, and not replacement).

However, New South Wales has confused the issue in that state with recent reversals of position on CSG development within the state. While the opposition by groups like Lock-the-Gate led to a moratorium on hydraulic fracturing in New South Wales, the government lifted the ban following extensive research and study of the environmental issues and the available courses of mitigation of environmental degradation. It then reversed itself in February 2013 by imposing strict limitations on development, imposing buffer zones around residential areas and specifying no-go zones. However, given the scale of the resource, this may be more of a domestic issue with little bearing on international trade of natural gas.

Beyond the issue of ownership differences between surface and sub-surface, Australia also acknowledges native title to some lands. The official recognition dates back to 1993 with the passage of the Native Title Act of 1993. Many of the natural gas projects in Australia must address native title, and where it applies there must be a negotiated settlement before development may proceed. Issues around native title, and others, frustrated the development of the Ichthys project in Western Australia and led to the onshore portion of the project being located in Darwin, in the Northern Territory, even though this requires a subsea pipeline of more than 800 km from the Offshore Western Australian resource. The proposed Browse project also faced challenges from some of the Aboriginal community over title and share of benefits related to the planned development at James Price Point, north of Broome. While it has been emphasized that these land and environmental issues were not central to the decision to cancel the onshore development, the influence of these issues on the riskiness of a potential project should not be dismissed.

While issues have arisen about how domestic gas prices may be affected (or should be affected) by the large-volume export projects, the proposed projects that are currently under construction, or those in operation, have received their approvals and signed contracts to export. Since Queensland does not already have in place a domestic reservation policy, one must wonder at the legal ability to apply one retrospectively to the projects already approved and under construction. The domestic pricing issue seems to miss the fact that most of the gas resources being developed for export would not be developed for domestic markets because the relatively small size of the markets would translate into even higher cost gas than now expected.

## Economic Conditions

Australia's economy is frequently characterized as a two-speed economy. This characterization is meant to capture the fact that Australia is in the midst of a resources boom, in both energy and mineral resources,[28] which is not equally shared by the manufacturing or services sectors; the concept of Dutch disease is raised occasionally to explain this situation.[29] The primary driver of the resources boom and Australia's current economic dynamism is China's continued growth. But it also rests significantly on the relatively high primary commodity prices being experienced generally around the globe. For natural gas developments, China's continued growth in energy demand is a significant factor, but Japan is still the dominant importer. Moreover, contracted volumes for Australia's LNG-based natural gas export projects are spread across all of Asia's regional natural gas consumers.

Nevertheless, any concerns about China's growth send ripples of concern through business and political sectors. China's overall growth may be questioned from time to time, but the expectations related to energy demand growth rarely seem to be questioned. Even somewhat slower overall economic growth in China is likely to continue to support, even require, continued expansion of energy systems to meet growing domestic demand for energy services aimed at rising to international standards. One of these important energy services is electricity generation, and Australia's natural gas is likely to continue to find a growing market. Recent proclamations from China continue to emphasize its intent to significantly expand its use of natural gas and to increase its share in the country's primary energy mix. And this is expected to continue to call for imports.

Just as the expected increase in domestic natural gas use does not rest upon any specific government being in office, the economics of Australia's natural gas export industry do not

[28] In addition to the $190 billion in LNG projects under construction, there is in excess of $200 billion of projects at various stages of commitment and development in the minerals sectors of Australia. This value varies over time as some projects are completed and new investments are undertaken. See, *Resources and Energy Major Projects*, various issues, published by the Bureau of Resources and Energy Economics, Australia Government, available for download at www.bree.gov.au.

[29] The dynamic growth in the resources sector, driven by significant demand for exports and relatively high commodity prices, simultaneously drives up the value of the Australian dollar and diverts resources from manufacturing and services to the resources sector. This drives up costs in the manufacturing and services sectors while undercutting the competitiveness of these sectors, both with respect to export markets and against imports.

rely solely on China. Australia's natural gas exports have been spread over a range of importing countries. The dominant importer has been, and continues to be, Japan. However, over the period since 2005, importers of Australian LNG have included Kuwait, the United Arab Emirates, China, India, Japan, South Korea, and Taiwan. There were even export volumes, albeit quite limited, from Australia to the United Kingdom in 2009. Nevertheless, over this period, the share going to Japan has typically exceeded 70% of Australia's exports.

While China has grown to account for about 20% of Australia's exports, China also appears to desire diversification in its natural gas import portfolio. China's first imports came from Australia in 2006, but by 2011 China was importing LNG from 12 countries. Australia continues to represent the largest share of China's LNG imports, with 4.95 Bcm, or about 30% of China's LNG imports. In addition to the expansion in LNG imports and planned domestic resource development, China is also planning to expand its pipeline imports. First pipeline imports were sourced in Turkmenistan and transited through Kazakhstan to one segment of the West-East Gas pipeline, and these have been followed by the recent opening of the Myanmar-China pipeline with an annual capacity of 12 Bcm. There are also negotiations with Russia related to two potential pipeline projects, but there has been a long-standing impasse on the determination of price.

Therefore, it appears that both Australia and China desire to maintain diversification in their portfolios of buyers and sellers, respectively. The desire for diversity extends across all importers and exporters. However, while Australia's share of China's LNG imports has fallen with this diversification, the size of the China LNG-import pie has increased such that Australia's export volumes to China have increased in absolute terms. This is expected to continue into the future.

The question for Australia has more to do with the possibility of further developments of green fields export projects and incremental additions to existing and currently under construction projects than to near-to-mid-term activity. Australia is currently likely at its limits to bring projects to completion; some would say it is beyond its limits and significantly constrained by both labor and capital equipment limitations. Indeed, the previous Labor government stated that it did not see the need for further developments beyond one or two additional green fields projects. On Jan. 18, 2012, The Australian reported that "the Gillard government says it will discourage more onshore stand-alone liquefied natural gas plants, apart from the controversial Browse project planned near Broome and another potential Gladstone plant, with six LNG hubs in Northern Australia seen as enough." The Abbott government may be more open to additional development, especially for FLNG. It is in this context that concerns for future economic growth rates for China and India and other natural gas importers in the region are occasionally raised.

The strain on the system of this rapid development is revealed in the costs of doing business. The economics of the natural gas sector in Australia is complex. There are very high construction and operating costs, but these are somewhat offset by favorable shipping distances relative to most competitors. However, the bottom line for project developers is also affected by carbon pricing and resource rent taxation policies. Each of these is discussed briefly below.

*High Cost of Business*

It has been claimed by some in the industry that Australia is the most expensive jurisdiction in the world for LNG projects. For example, the Gorgon project is expected to cost at least $55 billion (having been increased recently from an initial estimate of $45 billion, but with installed capacity also increasing from 15.0 to 15.6 mtpa), implying over $3,500 per installed ton per year (tpy) of LNG production capacity. The Ichthys project is expected to cost $34 billion, implying over $4,400 tpy of capacity. While these costs are now the norm in Australia, the global average is closer to $1,000 per installed tpy.

*Distance Advantage*

On the other hand, Australia's location is beneficial, especially in light of its higher costs of doing business. The shipping distances between Australian projects and ports and destination markets in Asia are considerably shorter than those for, say, Qatar, currently the world's largest exporter of LNG-sourced natural gas. The shipping distance between Qatar and Tokyo is 6,522 nautical miles (nm), which at a speed of 14 knots requires 19 days and 10 hours. For Australia, Darwin is the closest and Dampier (home to the North West Shelf and Pluto projects in WA) and Gladstone (home to the CSG-based projects in Queensland) are effectively equidistant from Tokyo. The Darwin shipping distance is 2,960 nm, requiring eight days and 19 hours in transit, while for Dampier and Gladstone the distance is 3,742 nm requiring 11 days and three hours at 14 knots.[30] Darwin thus has about a $0.45 per MMBtu shipping advantage over Qatar.[31]

Australia also has a considerable distance advantage over potential shipments from the United States Gulf coast. Travelling by way of Panama, the distance from Houston to Tokyo is 9,247 nm, requiring 27 days 13 hours, and travelling around South Africa makes it 15,957 nm, requiring 47 days and 12 hours in transit. Thus, Australia will maintain its significant advantage in shipping costs, which will help to offset the higher operating costs faced by its projects.

*Carbon Price*

The carbon price introduced by the Gillard government would have an effect on the natural gas export sector of Australia. Australia is the only LNG-based natural gas exporting country in the world to impose a carbon tax on the industry. LNG exporting facilities are covered by the emissions limits, however their exposure is initially limited. LNG projects will receive a minimum of 50% of their emissions permits free.[32] The following example is indicative of the effect of the imposition of the tax to the bottom line of the Australian projects if it is not repealed.

**Australian LNG and the Price of Carbon**

The CO2 pricing policy of the Australian imposes additional costs on LNG exporting projects that most likely will not be able to be recouped through pricing of the exported natural gas. The natural gas marketed in Asia, the primary market for Australian exports, is currently priced against crude oil, and contracts appear to not allow for an additional charge in response to the additional costs resulting from the tax on CO2 emissions. The additional costs for each project will differ according to the specifics of the LNG production system and the CO2 content of the original natural gas production stream.

[30] The nautical distances and transit times are taken from www.searates.com.
[31] This estimate is based on tanker daily rates at $125,000 for a 140,000 cubic meter LNG tanker, which equates to roughly 3 million MMBtu, and the 11 day shorter travel time.
[32] While the initial carbon pricing mechanism has all the hallmarks of a tax, the official position is that it represents a permit price. Those entities with obligations will be required to buy permits sufficient (and no more) to cover their emissions level from the government and to immediately surrender them.

An example of the impact of the CO2 tax may be seen by examining the Ichthys project, offshore Western Australia and piped to Darwin. The taxing scheme recognizes the importance of emissions intensive trade exposed industries like that of the LNG exporting sector. As a result, the scheme provides for allowances of at least 50% for LNG exporting projects. The Ichthys project will produce and export 8.4 mtpa of LNG, and it is projected to emit 7 million tons of CO2 per year. The 50% allowance implies the project will have an exposure on 3.5 million tons per year.

The $23/ton tax imposed for the 2012-2013 period implies an exposure of $80,500,000. This additional cost will be spread over the delivered export volumes, which amount to more than 408 million MMBtu.[33] So the CO2 tax exposure increases the cost of delivered natural gas by roughly $0.20 per MMBtu. If Australia experiences annual inflation of 2%, the 2014-2015 cost will be $0.22.

Similar analyses for Wheatstone (estimated annual CO2 emissions are 9.9 million tons) suggest an annual exposure of approximately $114 million. This cost will be spread over the 8.9 mtpa of LNG (or 432 million MMBtu), which implies $0.26 per MMBtu; with 2% inflation this will rise to $0.29 for the 2014-2015 period. And, for the 3 mtpa coal-seam-gas fed GLNG export project, the cost per MMBtu will be about $0.20, rising to $0.22 for the 2014-2015 period.

While these cost estimates per MMBtu may not seem too large, if not repealed, they will offset the favorable shipping-cost differentials between Qatar and Australia to most Asian ports by nearly half.

At this time, it is quite unclear in which direction the price of CO2 emissions would move if not repealed and Australia shifts to a permit trading scheme and away from the fixed tax. The current EUA (European Union Allowance unit) prices are around € 6 per tonne, which converts to about A$7.50 at current exchange rates. This may suggest an eventual significant fall in the annual exposure. However, this is one of the more uncertain markets, so it would be rather foolhardy to assume such a fall. Moreover, with the lower bound set to A$15.00

[33] LNG tonnes to Btu conversions are based on those found in the annual BP Statistical Review of World Energy; 1 million tonnes of LNG equals 48.6 trillion Btus.

(escalated at 4% per annum for the first five years of market pricing) any market-driven fall would be constrained, and there would continue to be substantial exposure.

*Resource Rent Tax*

In addition to the carbon tax, as of July 1, 2012, the Petroleum Resource Rent Tax (PRRT) will apply to all offshore and onshore oil and natural gas projects. The PRRT is a profits-based tax, with a 40% rate, and it applies to crude oil, natural gas, and coal seam gas, and also now captures the North West Shelf Project in its coverage. Prior to July 1, 2012, the PRRT applied only to offshore projects, and it excluded the North West Shelf Project. For onshore projects, state royalties, typically 10% of wellhead value, are deductible against PRRT liabilities.

The positives and negatives will be internalized by the project developers and felt on the bottom line. This is because the delivered price received for the natural gas is set by contract and linked to the price of crude oil in the Asian markets.[34] The price is not the summation of the costs, but rather the result of market forces in the consuming countries, albeit indirect forces via the market valuation for crude oil. Project developers realize the netback value, which will account for shipping and liquefaction costs.

Nevertheless, the dynamism of the Asia-Pacific region is quite likely to support and spawn additional export-oriented projects in Australia's natural gas sector, whether they are expansions of existing projects or economically justified new green fields projects. Neither side of politics actually seems likely to arbitrarily block a project proposal that can be shown to have a solid economic justification. The Browse Project provides an interesting look into the cost issues faced in Australia as well as the industry's view on the likely demand for natural gas going forward.

The Browse Project is not currently under construction, but it is considered by many to be both the next most likely project to go forward and a test of the economic viability of future projects. Plans called for the project to be developed with liquefaction facilities built at James

[34] It should be noted that the long-term contracts for LNG tend to contain renegotiation/reopener clauses, which may lead to adjustments to the pricing terms. However, it appears that such renegotiation is infrequent and slow. Moreover, most who suggest that these clauses may be employed to de-link LNG pricing from crude oil expect that natural gas prices will fall as a result, which will not be helpful to Australian projects experiencing cost escalation and increased tax burdens.

Price Point, north of Broome in Western Australia. The project had strong support from the WA government, and in particular from Premier Barnett, and from Woodside Petroleum, which would be the operator. The project at James Price Point was cancelled in April 2013, with Woodside citing high costs as the reason. However, at the same time that the onshore James Price Point option was cancelled, the project partners noted that they would now closely investigate their option of developing the natural gas resources via FLNG. So in one action the developers of Browse simultaneously signal that Australia is very costly, in part because of the stiff competition for the same labor and capital from several projects, but they also believe that Asia and the rest of world will be increasing the demand for natural gas, calling for further resource development. This is clearly an economic decision. While the premier argued that modelling showed that James Price Point would be profitable, the fact is that there are potentially more profitable (and perhaps lower risk) ways to develop the same resources.

Beyond the specifics of the current and potential LNG, export-focused projects in Australia, there will likely be continued growing levels of activity on the exploration front in search of commercially viable shale gas and tight gas resources. These activities may well have their greatest initial influence on domestic natural gas markets and prices, but the potential resource base is also likely to provide additional support to expansions of the LNG-based export capacity.

## Scenarios

Several scenarios may be envisioned for the future of Australia's natural gas developments and its role in the geopolitics of natural gas. Two such scenarios are US LNG exports[35] to Asia and Chinese domestic development of significant shale gas resources. Will either of these possible future developments have a significant impact on Australia's geopolitical role in the Asia region or globally?

[35] Much of what follows will likely apply to potential Canadian LNG exports to Asia. Indeed, Canada will not face the issue of requiring the expansion of the Panama Canal to make its proposed projects economic since these projects are to be based on the West Coast in British Columbia. Australia will still have a shipping distance advantage, albeit smaller than relative to the US.

*US LNG Exports to Asia*

The possibility of the United States becoming a significant natural gas exporter with the development of LNG export capacity has raised questions about the potential market implications for natural gas markets around the world. How much gas will be exported and what these quantities will do to current prices, and pricing mechanisms, are the primary questions heard and written about. So while the US is still working through a range of export approval processes, the rest of the world, including Australia, is trying to determine whether or not this will be a good thing or a bad thing and for whom.

It is important to understand that neither Australia's nor the potential volumes from the US are entering a static marketplace. The quantity of natural gas demanded in the Asia region has been on a steep rise, and this is expected to continue. BP's recently released Outlook to 2030 projects an increase in total natural gas consumption—including supplies from domestic production, LNG imports, and pipeline imports—in the Asia Pacific of 29% by 2015 and 60% by 2020 from a 2011 base. BP also projects that Asia Pacific production will increase by only 18.8% and 52.1% to 2015 and 2020, respectively, on the 2011 base.

In other words, Australia's increased export volumes and the potential volumes from the US will enter a rapidly growing market and one where regional production is not expected to keep pace with consumption. In terms of millions of tonnes per year, the total Asia Pacific consumption-production gap in 2011 equalled 82.3 mt. The equivalent measure projected for 2015 is 141.2 mt and for 2020 it is 159.2 mt. The LNG production capacity under construction at the beginning of 2013 equals 95.3 mtpa, which includes the 61.5 mtpa from Australia and 9.0 mtpa of Cheniere's Sabine Pass project in the US. This implies a consumption-production gap of 63.9 mt by 2020 when all of the currently under construction projects should be in operation. So while there are several proposed LNG export projects from the US (not all of which are aimed at Asia), there appears to be a sizable market gap to be filled in just the Asia Pacific.

From both the Australian and the US perspective, this is quite appealing. While there will be no shortage of competition from other participants in these markets, a greater benefit would be expected to accrue from entering a rapidly growing market compared to entering a static one. Entering a static market, especially with significant volumes, portends a decrease in price and an attendant shrinkage of margins. The incentive to transform North American natural gas into LNG for shipment to the Asian markets is based on the current significant price differentials between North American prices and those in Asia. Given shipping distances, even with an expanded Panama Canal, it will not take a huge drop in the Asian price, or rise in the US price, to make LNG shipments from the US Gulf marginal, at best. It is also expected, but as yet unknown, that the transit fees for the expanded Canal will also increase, thus limiting to some extent the attractiveness.

The main risks to Australian LNG exports (particularly additional projects or project expansions) is not the potential competition from US exports but rather Japan's return to significant use of their nuclear power system[36] and/or China's significant development of its domestic resources, both conventional and unconventional, or substantially increased pipeline import capacity.

*China Domestic Production Expansion*

Within Australia there is also a concern that demand for natural gas exports will be severely curtailed if and when China develops its domestic natural gas resource to a substantial extent. China already produces 128% more natural gas than Australia, yet its imports, via LNG and pipeline, continue to grow. This is in part due to the fact that natural gas accounts for only about 4.5% of China's primary energy mix, compared to a global average of over 23.6%, and China's intent to significantly expand the gas share.

This is also a familiar pattern in China as seen with coal imports. China is the largest producer of coal in the world, yet it continues to increase its imports of coal, including volumes from Australia. So do Australian natural gas exporters or the government, with respect to its expected revenue benefits, need to be concerned about either existing export capacity being made redundant or that planned, but as yet not committed, projects will not be needed?

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[36] The BP consumption projections for the Asia Pacific assume that about half of Japan's currently shut nuclear power plants come back online by 2015, with dependency declining as plants are retired with no extra-ordinary lifetime extensions. Based on personal correspondence.

If instead Japan returned to previous nuclear power levels and plans for expansion the implications for natural gas demand will depend on how its share of electricity generation relative to oil and coal evolves. But Japan's commitment to $CO_2$ emissions reduction should maintain a significant role for natural gas and hence for continued imports. This may be tempered somewhat with Japan announcing that it will sign a successor to the Kyoto Protocol.

China is believed to have the greatest potential shale gas resource of any country in the world. The EIA study estimated the risked, technically recoverable resource at 1,115 tcf (down from the 1,275 tcf estimate in the 2001 EIA study). The potential for large-scale increases in domestically produced natural gas in China, from all sources including shales and coal bed methane, will not necessarily place significant downward pressure on its medium- to long-term demand for LNG imports. Similar to the reasons for China's significant coal imports, LNG imports will be required for quite some time to meet the requirements of the coastal cities that lie relatively far from the most prospective domestic gas resources, including those for shale gas.

Significant development of China's domestic natural gas resources would more likely have a negative impact on Australia's coal exports than on its natural gas exports. The majority of China's prospective natural gas resources, especially its shale gas resources, are located closer to the interior of the country, and some in the very far West, than to the coastal regions where both LNG and coal imports arrive. China appears to import coal not because it does not have sufficient reserves but rather because it is too costly, i.e., uneconomic, to transport its domestic coal from the northern and interior production locations to the coastal cities that require the energy. Since China has historically been defensive of its domestic coal industry, which employs significant numbers, and it has made strong declarations regarding reducing air pollution problems in its cities, it is likely that natural gas imported as LNG to the coastal regions will displace imported coal before domestic natural gas production will displace LNG imports.

China has relatively little domestic transportation pipeline capacity, in general, and very little reaching the rapid-growth coastal cities. Moreover, the terrain between the likely production regions and the coastal cities is mountainous and challenging, and therefore expensive to lay pipe. Just as with coal being imported rather than building more rail capacity to the coast, natural gas is likely to continue to be imported as LNG to satisfy the growing energy needs of these dynamic cities. The Chinese government goals and commitments to reducing air pollution and reducing energy intensity will further stimulate the use of natural gas, requiring import growth, at the expense of coal imports, not LNG imports.

## Conclusion

Australia will be a key player in the global trade of natural gas for several decades, at least. Moreover, this influence is based on actual projects already operating or already under construction; it does not rely on speculation of possible future project development. The three operating and seven under-construction LNG projects will propel Australia into the upper echelon of natural gas, LNG-exporting countries. And new technologies being employed in Australia's high-cost (but stable) environment may well set the path and direction of future developments elsewhere in the world. Australia represents a stable, inviting environment for the continued development of its world-class natural resources, and natural gas is expected to continue to play a significant role in its future under a range of likely scenarios. Moreover, Australia's natural gas exports may likely limit the geopolitical power or adventurism of others within the Asia Pacific region and beyond.