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Projections for Eastern Australia's LNG Export Revenues: Opportunities and Risks in the Asia-Pacific Region

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Keywords

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JEL Classification

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Projections for eastern Australia's LNG export revenues: Opportunities and risks in the Asia-Pacific region

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Further links to the international LNG market implies that eastern Australia's LNG export revenue will also depend on future LNG prices in the region. This paper provides the estimation of eastern Australia's export revenue over the period of 2015–30 for different alternative LNG expansions, using different LNG price scenarios in the Asia-Pacific. The first case considered of future LNG exports is the 7 train Core case, which is based on the AEMO (2013 and 2014) and the Core Energy Group (2013). The second case of future LNG exports is based on the IES (2013). In each case of Australia's future LNG development, three different scenarios of low, medium and high values are considered. For the first case, export revenues range from A$17–23 billion by 2020, and A$21–27 billion by 2030. For the second case, export revenues for all scenarios of LNG prices range from A$19 billion to A$33 billion by 2020 and A$21 billion to A$39 billion by 2030.

1. Introduction

Global gas trade has been expanding and is greater than ever, of which liquefied natural gas (LNG) is clearly the fastest-growing component. Over the past decade, LNG international markets have been changing rapidly with a global growth rate of 7.6 per cent a year, and contributing 31.4 per cent of global gas imports in 2013 (International Gas Union (IGU) 2014a, 2014b and British Petroleum (BP) (2014a). Over the long term, LNG exports are projected to expand rapidly at an annual growth rate of 3.9 per cent (more than twice as fast as gas consumption), accounting for 26 per cent of the growth in global gas supply by 2035 (BP 2014b). The Asia-Pacific, where LNG dominates 81 per cent of gas trade, is the biggest and fastest growing LNG market in the world. Since the first LNG imports in the 1970s, LNG imports in the region have been increasing rapidly, accounting for 73 percent of global LNG imports in 2013, of which Japan and South Korea accounted for 50 per cent and 17 per cent of these imports, respectively (BP 2014a). Over the past decade, LNG imports in Asia-Pacific have more than doubled and increased at a remarkable growth rate of 8.4 per cent per year (International Group of Liquefied Natural Gas Importers (GIIGNL) 2004–14).

Australia's LNG industry has seen an extraordinary development. LNG exports, which were 23.7 million tonnes (MT) and valued at around $16.0 billion in 2013 (based on IGU 2014a and Che and Kompas 2014a), are expected to increase by three-fold in the next few years (Australian Energy Market Operator (AEMO) 2014). At present, more than two-thirds of the world investment in LNG liquefaction is occurring in Australia. Based on coal seam gas, the eastern market is undergoing a substantial process of integration with the LNG Asia-Pacific market. From the end of 2014, starting with Gladstone, seven new LNG liquefaction facilities (valued up to A$200 billion) will provide a capacity of LNG supply about 61.8 million tonnes (MT) a year (GIIGNL 2014 and IGU 2014a). With new LNG expansion, Australia's LNG exports are expected to reach 79 Mt per year by 2020, making the nation the largest LNG exporter in the world.

Eastern Australia's LNG development is especially striking. The region has been undergoing a substantial transformation to become an important LNG exporter of coal seam gas. By integrating to to the Asia-Pacific LNG market, eastern Australia's LNG development will be

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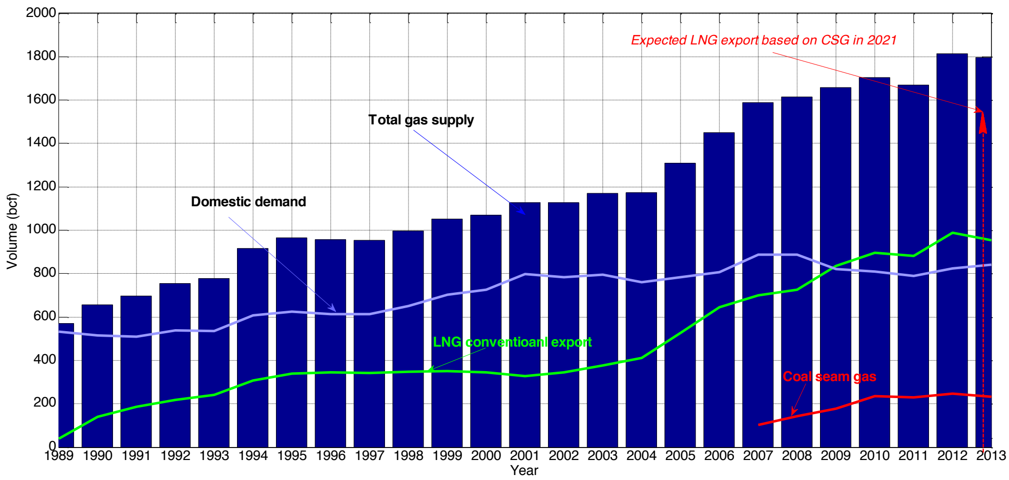
affected by all the issues and uncertainties surrounding the dynamics of LNG pricing in the market. Historically, the Asia-Pacific market has been based on the oil linked mechanisms and long term contracts since 1908s. LNG contract prices are referenced to the JCC crude oil price with a S-curve characteristic. However, in the post-Fukushima period, there have been substantial changes in the dynamics of future LNG prices in the Asia-Pacific as analysed by Che and Kompas (2014a). As a result, Australia's future netback prices are different and depend on different scenarios for LNG prices. Developing further from Che and Kompas (2014a), this paper aims to estimate eastern Australia's future export revenues based on different cases of LNG expansion using different possibilities for future LNG pricing in the Asia-Pacific. Part 2 provides a brief background of Australia's gas industry and markets. Part 3 reviews the projection scenarios applied to Australia's netback prices. Part 4 reviews different cases of LNG development in the eastern Australia market. Part 5 projects eastern Australia's LNG exports revenues based on different scenarios of LNG exports and LNG prices. Part 6 notes the key domestic issues that can influence Australia's future LNG export revenues. Part 7 concludes.

2. Background of Australia's gas industry and markets

2.1 Production, consumption and export

Over the past two decades, gas production, consumption and exports have been expanding rapidly in Australia, especially gas production and exports (see Figure 1). Driven by LNG exports, Australia's gas production has tripled from about 600 billion cubic feet (bcf) in 1989 to about 1800 bcf in 2013. Since the first exports in 1989, LNG exports reached to 900 bcf in 2013. During the last ten years, gas export and production has growing by 9.1 and 4.8 per cent per year, respectively (Australian Petroleum Production & Exploration Association (APPEA) 2014).

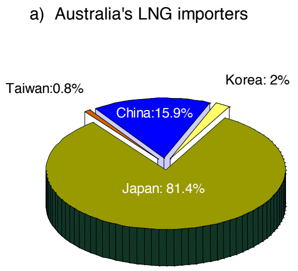
Figure 1: Gas production, consumption and LNG export in Australia, 1989–2014

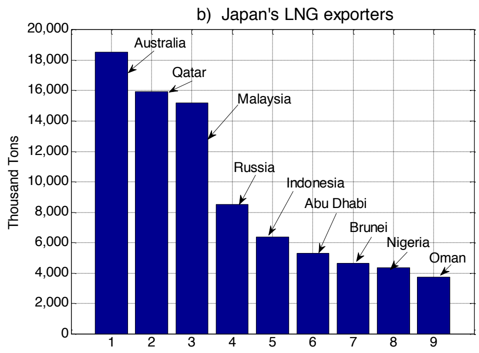


Source: Australian Petroleum Production & Exploration Association (APPEA) (2014).

The dominant LNG importer for Australia is Japan, which accounted for 81.4 per cent of total Australian LNG exports in 2013–14. The next largest LNG importers from Australia are China, South Korea and Taiwan (see Figure 2). For Japan, Australia is the most important LNG supplier, accounted for 22.5 per cent of total imports in 2013–14 (see Figure 2).

Figure 2: Australia's LNG importers and Japan's LNG exporters, 2013–14



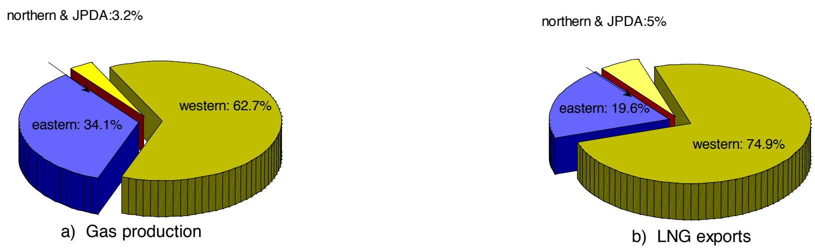


Source: Computed from GIIGNL (2014), Argus (2014) and Platts (2014).

2.2 Australia's regional gas markets

Given geographical location, its gas reserve basin, and production and consumption, Australia's gas markets are segmented by three major markets, including the eastern market, the western market and the northern market. The Joint Petroleum Development Area (JPDA), which is located in the north, is another area with LNG exports. In 2013, Australia's gas production was 2,028 billion cubic feet (bcf), of which the western, the eastern and the 'northern plus' (including the JPDA) accounted for 62.7, 34.1 and 3.2 per cent, respectively. Australia's LNG exports were 1,186 bcf, of which the western, the eastern and the 'northern plus' accounted for 74.9, 19.6 and 5.5 per cent, respectively (see Figure 3).

Figure 3: Gas production and export by regional market, 2013

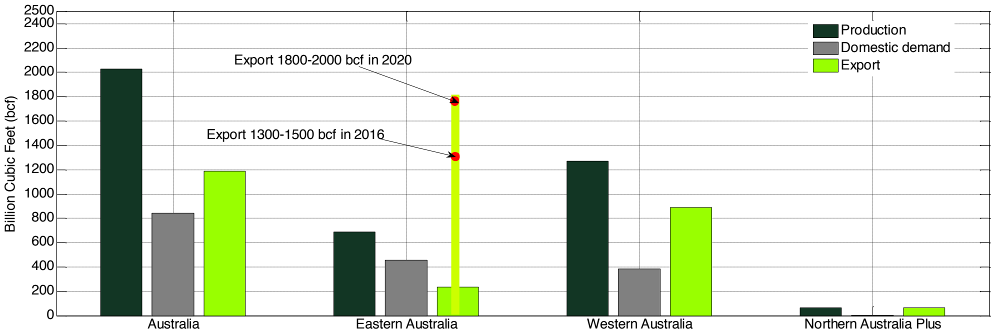


Source: Australian Petroleum Production & Exploration Association (APPEA) (2014).

In the eastern gas market, all gas producing and consuming regions (with the exception of the northern Bowen basin and Townsville in Northern Queensland) are interconnected by a transmission grid. Gas currently flows across many of the state boundaries, including from Queensland to New South Wales and South Australia and from Victoria to Tasmania, New South Wales and South Australia. In 2013, domestic consumption and LNG exports were 699 petajoule (PJ) and 256 PJ, respectively. For Australia, the market share accounted for 34.1 per cent and 54.3 per cent of of total production and consumption in 2013, respectively (APPEA 2014). Until recently, gas production in the eastern Australia was mainly based on conventional sources in the Victorian basins of Gippsland, Bass and Otway, with a smaller contribution from the Cooper basin in North-East South Australia-South-West Queensland. LNG exports were 232.9 bcf accounting for about 19.6 per cent of Australia production in

2013 (see Figure 4). Driven by future LNG export, which is based on coal seam gas, the eastern market has been on a fast track toward integration to the Asia-Pacific LNG market. The Gladstone LNG, the Queensland Curtis LNG, the Australia Pacific LNG (Queensland) are the most important LNG projects, which will increase the region's LNG exports from 11.8 Mt in 2015 to about 27.3 Mt in 2020 (Core Energy Group 2013). Based on the AEMO (2014), total gas production could increase by almost three-fold by 2020.

Figure 4: Gas balance in Australian markets, 2013



Source: the Australian Petroleum Production & Exploration Association (APPEA) (2014); Sources of the eastern Australia's future export are from the Core Economics, the GSOO-Gas Statement of Opportunities (AEMO 2014) and the Intelligent Energy Systems (IES) (2013).
Note: the 'northern plus' market includes the Bayyu Undan Joint Petroleum Development Area (JPDA).

The western market is a large, self-contained market located in Western Australia. Gas is delivered mainly by pipelines throughout the market. The market is the largest producing basin in Australia, augmented by extensive offshore conventional gas resources in the north-west and north. The market also has significant unconventional gas resources in the north-east, which are at an early phase of development. In 2013, the market accounted for 62.7 per cent and 45.6 per cent of 74.9 per cent of Australia's production and consumption, respectively (APPEA 2014). LNG exports in 2013 were about 890 bcf, sharing 74.9 per cent of Australia's total exports (see Figure 4). For future LNG development, the upcoming Gorgon project and the Prelude floating LNG platform, of which the full capacity is 15.6 Mt and 3.6 MT per year, respectively, are expected to commence in 2015 and 2017.

The northern market is a small market, accounting for about 5 per cent of Australia's total gas consumption (see Figure 4). Gas is delivered by two major pipelines here. LNG exports in 2013 were about 64 bcf, sharing 5.5 per cent of Australia's total export (see Figure 4). Future LNG supply is expected to increase by the Ichthys project at a capacity of 8.4 Mt per year. In the Joint Petroleum Development Area (JPDA), the Darwin LNG and Bonaparte Floating LNG projects are expected to add in 5.4 MT per year (Company Reports 2014).

3. Review of projection of Australia's netback prices

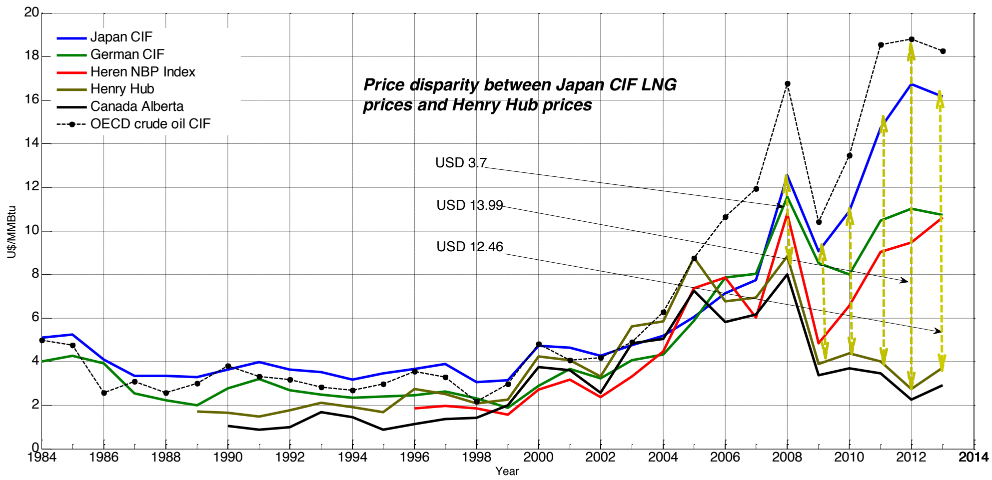
A study by Che and Kompas (2014a) provides an analysis of the dynamics of LNG price formation in the Asia-Pacific region and projections of future LNG prices and Australia's future netback prices based on different scenarios of future oil price. This section briefs the key outcomes of that study that will be applied in this paper.

3.1 Dynamics of LNG pricing formation in the Asia-Pacific

In the Asia-Pacific, the oil linked pricing mechanism and long term contracts still dominate LNG trade (IGU 2014b). For major LNG importers such as Japan and South Korea, price formula of LNG contracts is indexed to a price of a basket of crude oil imported to Japan, which is called the Japanese Custom Cleared price (JCC)[1]. However, there are the serious challenges facing this pricing mechanism, especially since 2008 (Stern 2014 and Roger and Stern 2014). Rising crude oil prices above U$100 per barrel (bbl) in early 2008 (World Bank (WB) 2014a) have caused LNG prices in the region to increase rapidly. The price disparity between international regions is becoming larger (see Figure 5). Additional gas demand for electricity power following the Fukushima accident (March 2011) have further accelerated LNG prices to historical levels, causing the largest ever price disparity between the Asia-Pacific and North America. Higher LNG consumption at historically high prices have put considerable pressure on LNG importers such as Japan, resulting in a significant loss of up to U$10 billion in 2011–12 (Federation of Electric Power Companies of Japan (FEPC) 2014). All these changes and further uncertainty over recent LNG prices have generated growing concern as to the efficacy of the JCC mechanism and whether it remains and appropriate pricing mechanism.

Figure 5: Disparity of gas price by international market

(US dollars per million Btu)



Sources: British Petroleum (BP) 2014a.

The traditional JCC linked pricing in the Asia-Pacific has experienced substantial changes over the past decade. The future dynamics of LNG pricing will change as analysed by Che and Kompas (2014a and 2014b), and the key features include: changes in the oil linked price mechanism; integration of Henry Hub pricing formation; impacts of changes in supplies and demands and the effect of the spot market on current LNG pricing in the Asia-Pacific.

Changes in the oil linked pricing mechanism

Based on the study by Che and Kompas (2014a), for the long term outlook, the JCC pricing mechanism remains important in the Asia-Pacific. However, the price slope of LNG prices

[1]The JCC price is the average price of customs-cleared crude oil imports into Japan (formerly the average of the top twenty crude oils by volume) as reported in customs statistics; nicknamed the 'Japanese Crude Cocktail'.

and JCC prices is getting smaller. The role of the base price in LNG pricing formation, which is independent of changes in crude oil prices, is getting larger and account for up to 68-70 per cent of pricing effects post 2008. There are a number of reasons for not changing the current oil linked pricing 'over night'. First, for LNG buyers, the 'risk aversion' characteristic of approaches to 'energy security' limit quick and significant changes in the current JCC pricing mechanism (i.e., with an approach usually geared to long term contracts). Second, there is resistance from LNG exporters to allow more market-based pricing given the large capital investment of LNG projects planned or in place, and the necessity to 'guarantee' returns if the oil linked price mechanism is entirely removed. Third, other alternative pricing formations also face their own issues. For example, for a future Asian hub pricing centre (IEA 2013), the issues of reaching agreements of key buyers and sellers and the progress (or lack thereof) of financial and legal regulations and hub locations are major challenges. As another example, the Gas-on-Gas pricing mechanism (driven by demand and supply), is vulnerable to geopolitical and catastrophic events (such as the Fukushima disaster) that can generate significant uncertainties in LNG prices in short terms.

Integration of Henry Hub pricing formation

Henry Hub prices are attractive to LNG importers in Asia-Pacific region and are historically volatile at lower and more stable levels than the fluctuations of crude oil prices. According to BP (2014b), the outlook of the USA's LNG exports is significant in the world and in the Asia-Pacific. However, over the long term, Henry Hub prices are getting more expensive (EIA 2014a), putting the key advantage of 'cheap' prices from the USA LNG supply at risk. According to Che and Kompas (2014a), it is unlikely US LNG will take a dominant part in the Asia-Pacific region. Given an increasing trend in Henry Hub prices and a decreasing trend for crude oil prices, the Henry-Hub linked price may be even higher than the JCC linked price after 2020.

Impacts of market conditions of LNG supply and demand

Rapid growth of shale gas and total dry gas in North America will provide an important source of LNG supply to the Asia-Pacific region (EIA 2014b). At present, LNG supply contracted from the North America to the Asia-Pacific is growing rapidly. In 2014, the contracts signed for LNG exports from the United States (US) to Japan will be about 12 MT or equivalent to 15 per cent of Japan's current LNG demand (estimated from the GIIGNL (2014) and the Petroleum Association of Japan (PAJ) (2014). The USA's LNG exports are projected to increase by roughly to 72.8 Mt in 2029 and remain at that level through 2040 (EIA 2014a). Approval of the Jordan Cove LNG export terminal in 2014 provides an important opportunity for added LNG exports from the US to the Asia-Pacific region. In addition, contracted imports of LNG from North America to Japan are growing, as evidenced by recent contracts with the US Cameron LNG project and the US Cove Point LNG project. However, there are challenges for future LNG expansion from North America to the Asia-Pacific region. First, transportation costs are uncertain and relatively high from the North America market to the Asia-Pacific. Despite the anticipation of the widening of the Panama Canal (which is expected to be a significant shipping route of USA LNG to Asia), which will reduce transportation costs, tariffs or conditions of passage for LNG cargoes are not yet confirmed. Second, the large investment required for LNG projects is a limitation for LNG development in the North America area (Herbert Smith Freehills Energy 2014).

LNG supplies from Indonesia and Malaysia as major exporters will decrease further under the effects of increasing domestic demand (resulted from economic growth and population growth) (IEA 2014). According to the IGU (2014) and Platts (2014), the Arun LNG liquefaction plant in Indonesia may even be converted into a regasification plant for LNG imports.

Overall, future LNG demand in the Asia-Pacific region is projected to be positive (WB 2014b and IEEJ 2014). LNG demand in other traditional markets (e.g., Japan, South Korea and Taiwan) will remain stable with economic and population growth. LNG demand in the emerging markets (e.g., China, India and Thailand) will grow (BP 2014b and IEA 2014). However, there are a number of risks from the LNG demand side that could make future LNG consumption in the Asia-Pacific highly uncertain.

On the demand side, changes in gas demand from China are important to the LNG Asia-Pacific market. China is in a 'golden age' of natural gas use with a rapid growth of consumption, rising by nearly seven times between 2000 and 2013. Rising incomes, rapid urbanisation, concerns about air pollution and increasing oil prices have favoured the switch from oil and coal to natural gas (Chen 2014). However, China's future gas demand could be met by rapid growth of domestic production. China's domestic gas supply is projected to grow rapidly during 2015–35 (5.7 per cent per year) (BP 2014b). Shale gas will likely make the largest contribution to growth (42.7 per cent per year), with most of it coming on line after 2020, and is expected to overtake North American of shale gas growth by 2027. Although China's gas demand growth requires a rapid expansion of gas imports (8.3 per cent per year), the gas pipeline from the Former Soviet Union (FSU) will be important source of gas imports (Chen 2014 and BP 2014b). It is important to note that China's future LNG demand is also uncertain given reforms of gas pricing and energy regulations. These issues include pricing levels and pricing structure; incentives for investments on production to import; infrastructure, transportation and storage. In addition, other important issues, which can influence China's LNG demand, are the oligopolistic structure of the suppliers dominated by three companies; and overlapping powers from different agencies and from the central and local governments (Chen 2014). The recent policy on nuclear energy will reduce Japan's LNG imports from 2015 by up to 10 MT/year (IEEJ 2014). Changes in nuclear power for electricity generation in Japan, South Korea and Taiwan could change significantly LNG demand in the traditional markets in the Asia-Pacific. A further analysis of the effect of demand and supply on LNG trade in the region is analysed by Che and Kompas (2014d).

Impact of development of the spot market

Given the major advantages of low and and relatively stable process and the uncertainties over crude oil prices, the spot market for LNG is likely to develop rapidly. The emergence and development of the spot LNG market in Asia Pacific, which is based on the Gas-on-Gas price formation, will also influence LNG pricing in the region.

3.2 Projection of LNG prices in the Asia-Pacific

LNG prices are projected based on the econometric results of the dynamics of LNG pricing in the Asia-Pacific (see Appendix B). Three different scenarios of long term projections for crude oil prices are used for the projection of LNG prices. They are the Reference and Advanced Technology scenarios of crude oil import prices in Japan by the IEEJ, the Reference case of Brent crude oil prices by the EIA (2014a) and the Reference case of WB (2014b) (see details in Che and Kompas 2014a). The projections of LNG prices for 2015–40 are programmed and stimulated in Matlab following from the econometric specification presented in Appendix B. The lower and higher bound of LNG prices are based on the standard deviation obtained from the econometrics results. Scenarios 1–3 indicate the projection of crude oil prices by the IEEJ, the EIA and WB, respectively. All values are at

2014 prices. The consumption Price Index (CPI) is from the World Wide Inflation data (2014).

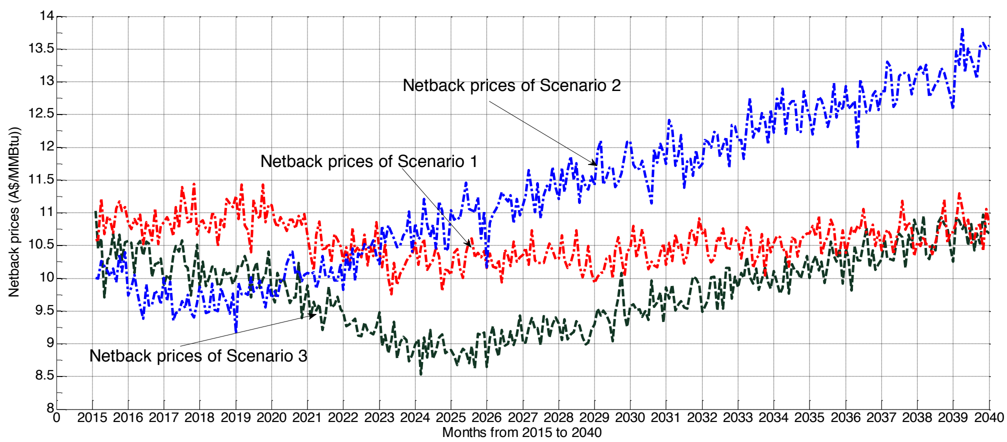
For Scenario 1, LNG prices are expected to be relatively stable and decrease during 2015–23 to more than U$14/MMBtu in 2023. The most likely LNG prices are projected to be stable with a marginal increase during 2023 to 2040, up to more than U$14.5/MMBtu in 2040. For Scenario 2, the most likely LNG prices are expected to decrease during 2015–18 at about U$13/MMBtu in 2023. However, since 2018, these prices are projected to increase, reaching more than U$16/MMBtu in 2040. For Scenario 3, projection of LNG prices shows a similar pattern to Scenario 1, but in general LNG prices are lower than those in Scenario 1, falling to around U$13/MMBTU for the most likely LNG prices over 2023–25. The most likely LNG prices are projected to be increase from 2023 to be around U$14.5/MMBtu in 2040 (see Figures B1–3 in Appendix B).

3.2 Projection of Australia's netback prices

The netback price is calculated by subtracting downstream costs, such as the transport costs of feedstock gas, liquefaction and shipping, from the delivered price of LNG to the export customer (Department of Industry 2014). Based on the projection of LNG prices over the period of 2015–40 and detailed costs by scenario of future crude oil prices, Australia's LNG netback price (A$/MMBtu) are projected (see Figure 6) based on different scenarios of LNG prices (see details in Che and Kompas 2014a). During the period of 2015–20, netback prices from Scenario 2 for LNG prices (using projections of crude oil prices by the EIA (2014) and Scenario 3 of LNG prices (using projection of crude oil price by WB (2014b) are relatively similar at around U$9.5 to U$10.5/MMBtu. During this period, netback prices based on Scenario 1 of LNG prices (using projection of crude oil price by the IEEJ (2014) are higher than those in other scenarios, ranging from U$10.5-U$11.5/MMBTu.

The period 2020–30 shows the opposite pattern of netback prices among different scenarios, including a decreasing trend for Scenario 1 and 3, but and increasing trend for Scenario 2. Since 2033, netback prices show a similar trend for Scenario 1 and 3, but a largely divergent trend for Scenario 2. The netback price disparity among these scenarios reaches maximum at about U$2/MMBtu during 2030–40.

Figure 6: Stochastic projections of Australia's netback prices, 2015–40 *(A$/MMBtu)*



Note: Prices are at 2014; Exchange rate for 2014 is provided from Reserve Bank of Australia (2014);

- Sources for long term crude oil prices used for scenario projection of LNG prices: ***Scenario 1****: the Institute of Energy Economics (IEEJ 2014),* ***Scenario 2****: the US Energy Information Administration (EIA 2014a); and* ***Scenario 3****: the World Bank (WB 2014b).*

4. LNG development in the eastern Australia

4.1 Development of major LNG projects

Based on the IES (2013), three planned projects in eastern Australia are the Australian Pacific LNG project; the Queensland Curtis LNG project and the Gladstone LNG project. Two other potential LNG projects are the Arrow LNG project and the Fisherman's Landing project.

Australian Pacific LNG

The Australian Pacific LNG project (APLNG) is a planned construction of a two train LNG plant at a capacity of 4.5 Mtpa per each (250 PJ/year on Curtis Island. The APLNG project has been planned to accommodate up to four LNG trains, with a collective output of up to 18 MTPA (990 PJ per year). Train 1 is on schedule to ship its first LNG cargo during mid-2015, while Train 2 is planned to be commissioned in early 2016.

After delays in the development of the upstream gas fields, primarily as a consequence of severe weather events across the 2010-11 and 2011-12 summers, an accelerated drilling program with the addition of some automated rigs has enabled the overall drilling program to again be on schedule. Construction for rest of the project, including gas treatment and water handling facilities, the main gas transmission pipeline and the Curtis Island LNG plant and associated infrastructure are on schedule for initial commission and first product shipment around mid-2015.

APLNG has a total of 2P gas reserves of 13,090 PJ which includes 38 PJ of conventional gas in the Denison Trough in the Bowen Basin. The 3P gas reserves are 16,026 PJ with a further 3,825 PJ of 2C contingent resources. APLNG has more than sufficient gas reserves to support its two train 9 Mtpa (495 PJ per year) project which will require 10,800 PJ for 20 years of operations (IES 2013).

Queensland Curtis LNG

The Queensland Curtis LNG project (QCLNG), which is in an advanced stage of construction, comprises two LNG liquefaction trains, each with an annual capacity of 4.25 Mtpa (235 PJ per year). The project has plans for the future installation of a third LNG train of comparable capacity. The project is on schedule to ship its first LNG cargo in early 2015.

While it is unlikely for immediate plans to proceed with a third LNG train due to the issues surrounding gas reserves, costs and market conditions, the project is ramping-up exploration for additional gas. This includes tight and conventional gas in the Bowen Basin, additional CSG in the Bowen and Surat basins and in unconventional gas in the Cooper-Eromanga basins. QCLNG has gross total 2P gas reserves of 10,326 PJ, sufficient for its initial two train LNG project for 20 years which will require 10,200 PJ. In addition QCLNG has 3P gas reserves of 18,876 PJ and a 2C contingent gas resource of 13,700 PJ (IES 2013).

Gladstone LNG

The Gladstone LNG project (GLNG) is well advanced in the construction in both the upstream aspects as well as for the two train liquefaction facility on Curtis Island. First LNG shipment is scheduled for mid-2015, with the second LNG train planned for commissioning mid-2016. The Curtis Island LNG plant is designed around an eventual three 3.9 Mtpa (215 PJ per year) LNG processing trains. The GLNG project will require 9,360 PJ of gas for 20 years of operation. Currently GLNG is short of gas in its own right having 2P gas reserves of

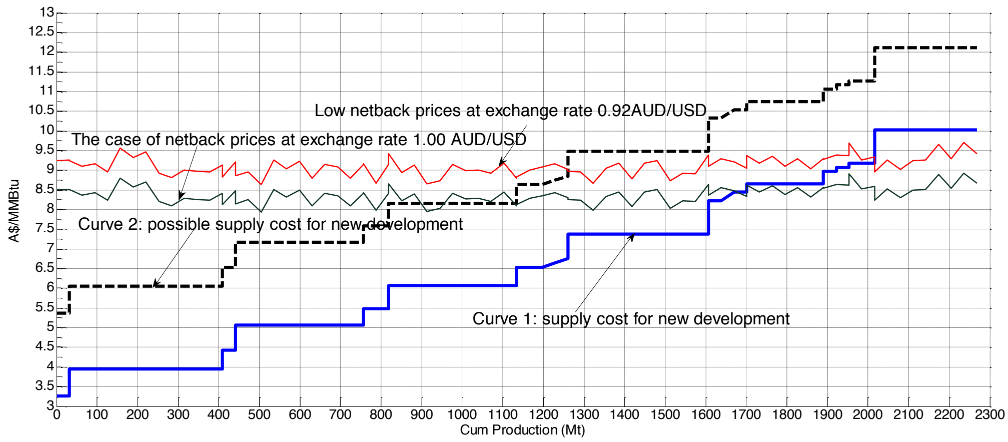
5,376 PJ or 11.5 years supply at full production. The project has 3P gas reserves of 6,823 PJ and 2C contingent gas resources of 1,638 PJ.

Other potential projects include: the Arrow LNG Project (8 Mtpa or 440 PJ/year); was planned to commence in 2017; the Fisherman's Landing: at the proposal stage is based on two LNG trains each with a capacity of up to 1.8 Mtpa (100 PJ/year) (IES 2013).

4.2 Costs of new gas development

Evaluation of the costs of new gas development is complicated, depending on specific conditions of individual LNG projects. Figure 7 provides an illustrated case for considering new gas development based on Australia's future netback prices and the cost of new gas development. Based on a study by the Intelligent Energy Systems (IES) (2013), cost-supply for new unconventional gas and coal seam gas development is calculated in measurements of A$/MMBtu for price and Mt for cumulative production (see Figure 7). Note that according to the IES (2013), the current average cost of development for new unconventional and CSG gas is already approaching A$5.3/MMBtu. Therefore, following Che and Kompas (2014a), an alternative (Curve 2 in Figure 7) that is based on a revised Curve 1 by adjusting the current costs to be A$5.3/MMBtu is also included. For consideration of Australia's future LNG development, a low case of Australia's future netback price (based on Scenario 3 of LNG prices, which is referenced to the future crude oil by WB (2014b), is presented in Figure 7. The future netback prices and cost of new gas development indicate the limitation of potential LNG new gas expansion.

Figure 7: Cost of unconventional gas in the eastern market by basin in Eastern Australia

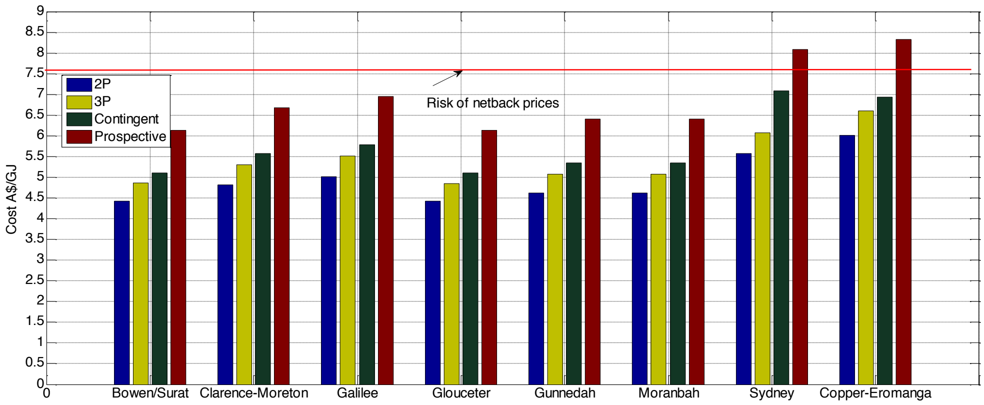


Source: Che and Kompas (2014a).

Using a low possible value of future netback prices (Scenario 3 that is referenced to assumption of crude oil prices by the WB (2014b), Figure 8 also provides another illustrated case of LNG expansion in the eastern Australian market. In Figure 8, the cost of unconventional gas in the eastern market is varied significantly by basin. For 2P reserve, the cost of new gas among basins can be different by A$2/GJ per basin. The low case of netback prices falling to A$7.6/GJ (or A$8/MMBtu) (in Figure 8) suggests the potential development of LNG for 2P, 3P and contingent reserves, but not for prospective reserves the Sydney or Copper-Eromanga basins.

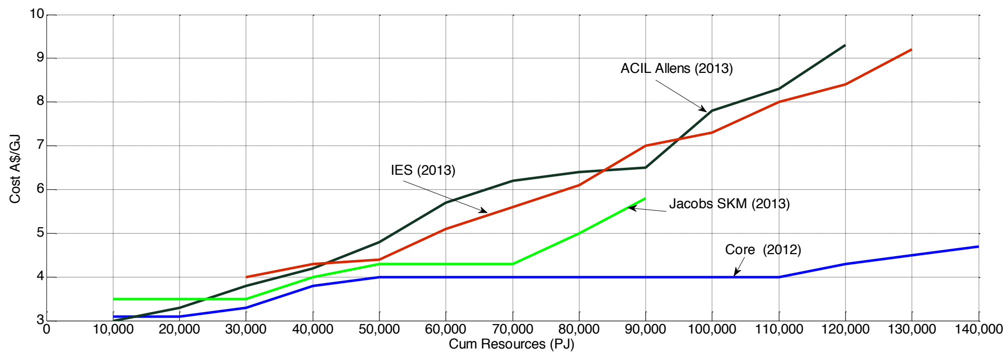
Measuring the cost of new gas development is a challenge due to differences in estimated costs of new gas development, as given by different studies (see Figure 9). The differences of costs of new gas development are the result of different assumptions, methodologies or surveys. While these costs are not much different for gas production lower than 50,000 PJ per year, there can be large differences, such as that between the Core Energy Group (2012) and the IES (2013) (see Figure 9).

Figure 8: Cost of coal seam gas in the eastern market by basin



Source: Intelligent Energy Systems (IES) (2013).

Figure 9: Cost of new gas development

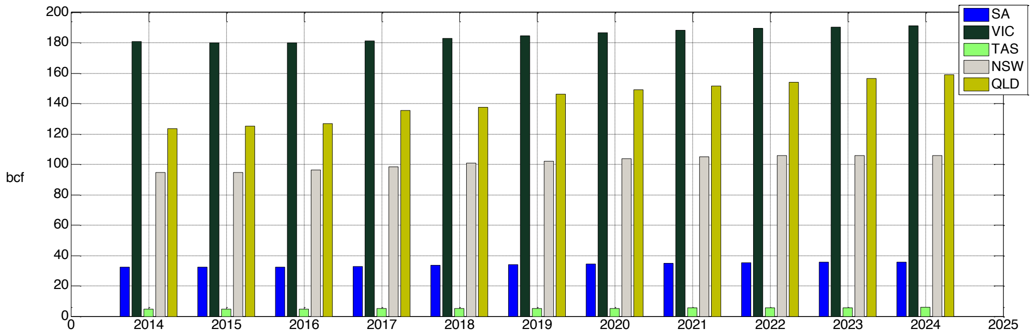


Sources: ACIL Tasman (2013), the Intelligent Energy Systems (2013), Jacobs SKM. (2013) and the Core Energy Group (2013).

4.3. Outlook of domestic gas demand

Based on the AEMO (2014), the domestic gas demand is expected to be relatively stable (see Figure 10). By 2025, the share of domestic demand is about 20 per cent of total gas supply (AEMO 2014 and the Core Energy Group 2013).

Figure 10: Outlook of domestic demand in eastern Australia, 2014–25



Note: Glastone adjusted; Source: Gas Statement of Opportunities (GSOO) (AEMO 2013–14)

4.4 Projection of LNG exports in the eastern Australia

The projections of gas production in the eastern market are analysed by different studies, including the Core Energy Group (2013), ACIL Tasman (2013) and the AEMO (2013 and 2014) (see Table 1). Figure 11 shows scenario projection of different cases of LNG exports with low, medium and high possibilities.

The Core 7 Train Scenario by the Core Energy Group (2013) includes:

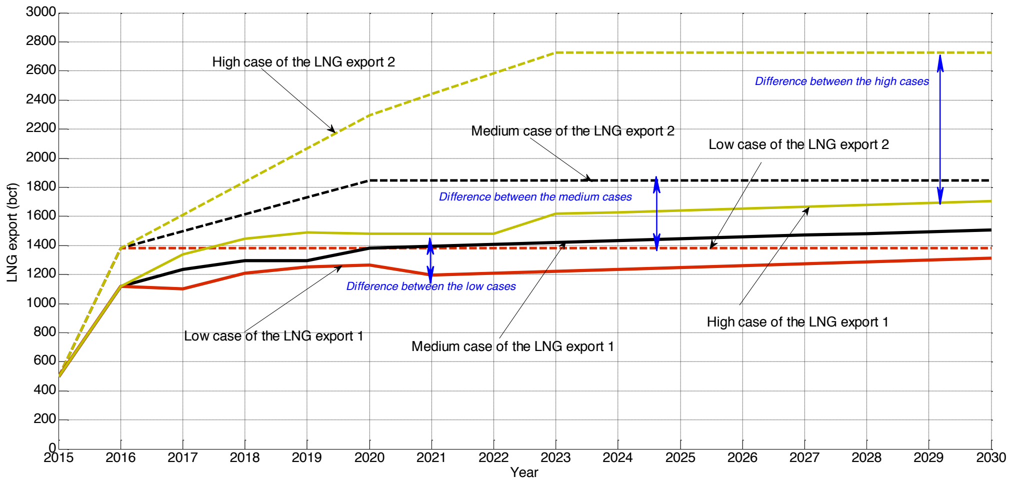
- Two Queensland Curtis LNG ("QCLNG") trains – starting LNG production in 2014 and reaching full capacity in 2016, with maximum gas demand of approximately 486 PJ per year.
- Two APLNG trains - starting LNG production in 2015 and reaching full capacity in 2017 of approximately 514 PJ per year.
- Two Gladstone LNG ("GLNG") trains – starting LNG production in 2015 and reaching full capacity in 2019, with maximum gas demand of approximately 446 PJ per year.
- One additional LNG train, Train 7, likely using Arrow LNG gas, requiring maximum annual gas demand of approximately 229 PJ per year.

Table 1: Outlook of LNG exports from the eastern Australia

Source	Outlook of LNG exports from the eastern Australia
AEMO (2013 and 2014)	based on the committed projects, 6 trains with revisions in 2014 with sensitivities of supply
Core Energy Group (2013)	Based on AEMO plus 16 % supply higher than AEMO since 2021 of Train 7 from proposed project
IES (2013)	6 trains with sensitivities of supply

Note: Sensitivities of production is based on utilisation of gas wells and production ram up.

Figure 11: Projections of LNG development in eastern Australia



Note: The LNG export 1 is based on the 7 train scenario by the Core Energy Group (2013) and the Gas Statement of Opportunities (GSOO) by the Australian Energy Market Operator (2013 and 2014); the LNG export 2 is based on the Intelligent Energy Systems (IES) (2013).

The projection of LNG development by the IES (2013) is based on six trains with sensitivities of supply (Table 1). The demand of LNG exports projected by the Core Energy Group (2013) increases rapidly for all scenarios, including the high case of the Core seven seven train scenario; and the low and high and the AEMO scenario (see the Core Energy Group 2013). The demand of LNG exports for the Core 7 train scenario projected by the Core Energy Group (2013) increases from 624 PJ in 2015 to be about 1600 PJ in 2020 (Figure 11).

5 Projection of eastern Australia's LNG export revenues

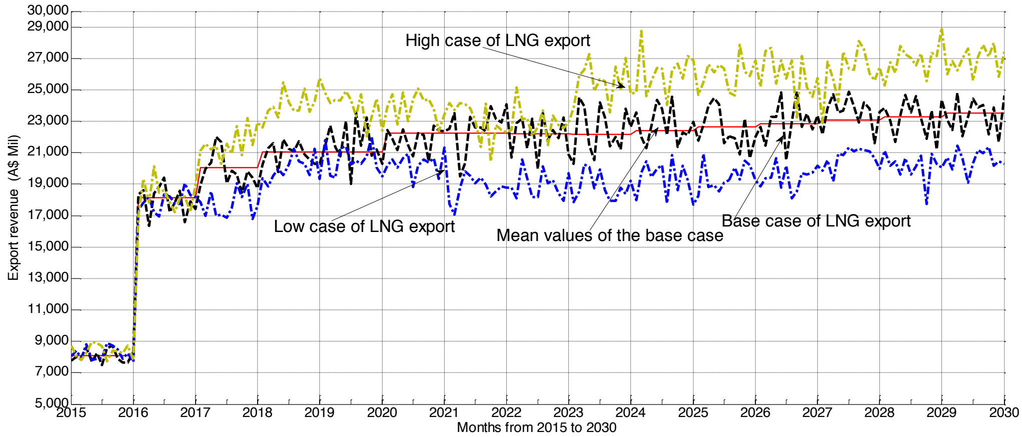
This section provides an estimation of eastern Australia's export revenue over the period from 2015–30. There are two cases of LNG export projections, including Case 1 of the LNG export that is based on the 7 train Core scenario and Case 2 of the LNG export that is based on the Intelligent Energy Systems (IES) (2013) (see Figure 11). For measuring LNG export revenues, three scenarios of LNG prices (as analysed in Che and Kompas 2014a) are analysed. Scenario 1 of LNG prices is referenced to the projection of crude oil prices by the Institute of Energy Economics (IEEJ 2014). Scenario 2 and 3 is referenced to the projection of crude oil price by the US Energy Information Administration (EIA 2014a) and the World Bank (WB 2014b), respectively.

5.1 Eastern Australia's LNG export revenues of the 7 train Core case

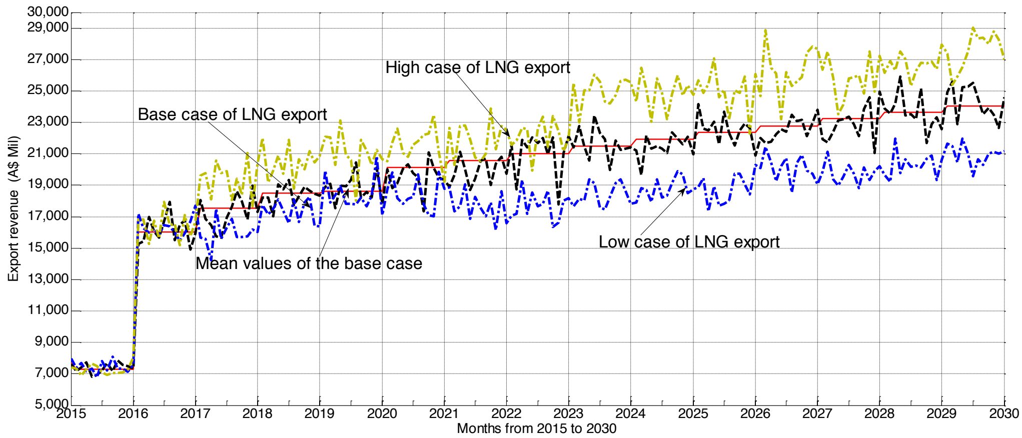
This section projects LNG export revenue based on the 7 train Core (Core Energy Group 2013) and the Gas Statement of Opportunities (GSOO) (AEMO 2014). The export revenues are simulated in Matlab based on uncertainties of prices obtained from the econometric analysis. Figure 12 presents the high, low, and most likely values of export revenues for three different scenarios of LNG prices. The values of export revenues for all scenarios of LNG prices ranged from A$17 billion to A$23 billion. By 2030, the values of export revenues for all scenarios of LNG prices in 2020 range from A$21 billion to A$27 billion. On average the differences in the most likely values of export revenues range from A$2 to 3 billion. The differences between the low case of export values (A$ 19 billion for Scenario 3) and the high case of export values (A$ 27 billion for Scenario 1) could be up to A$ 8 billion dollars.

Figure 12: Case 1: projection of LNG export revenues

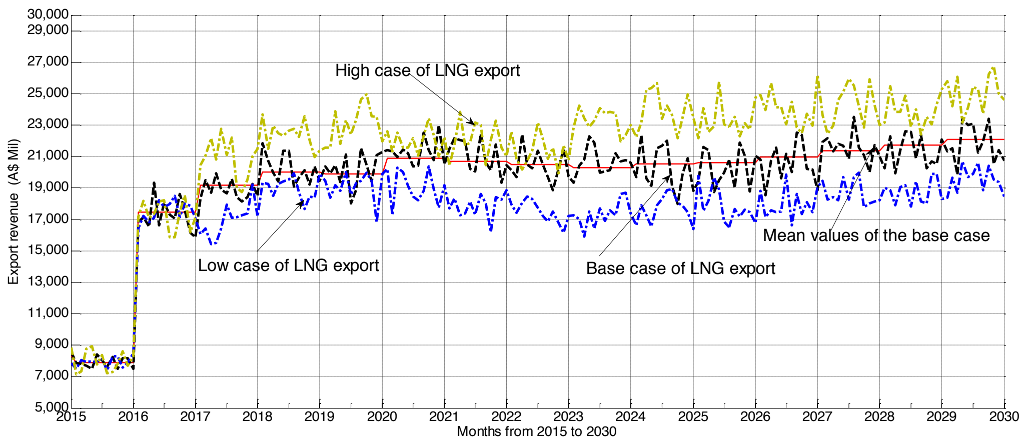
a) Scenario 1 of LNG prices



b) Scenario 2 of LNG prices



c) Scenario 3 of LNG prices



Note: Prices are at 2014; Exchange rate for 2014 is provided from Reserve Bank of Australia (2014);

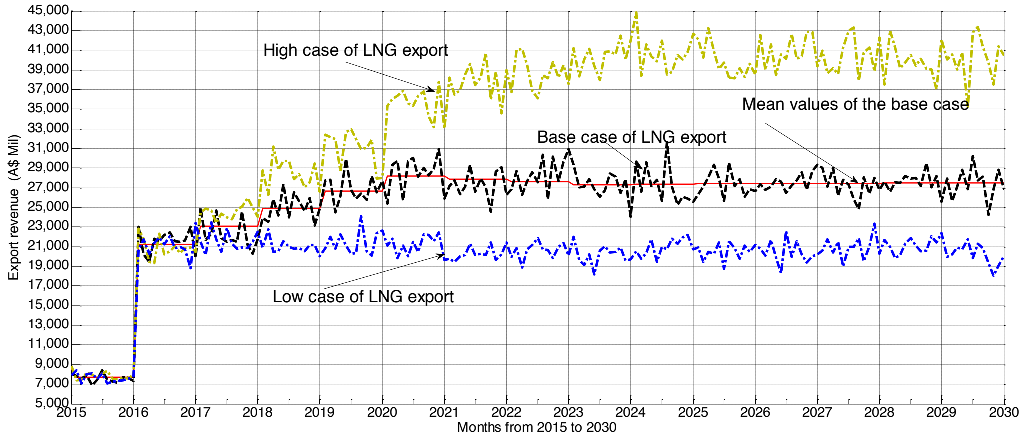
- *Sources for long term crude oil prices used for scenario projection of LNG prices:* ***Scenario 1****: the Institute of Energy Economics (IEEJ 2014),* ***Scenario 2****: the US Energy Information Administration (EIA 2014a); and* ***Scenario 3****: the World Bank (WB 2014b)*

5.2 Projection of eastern Australia's LNG export revenues of the IES case

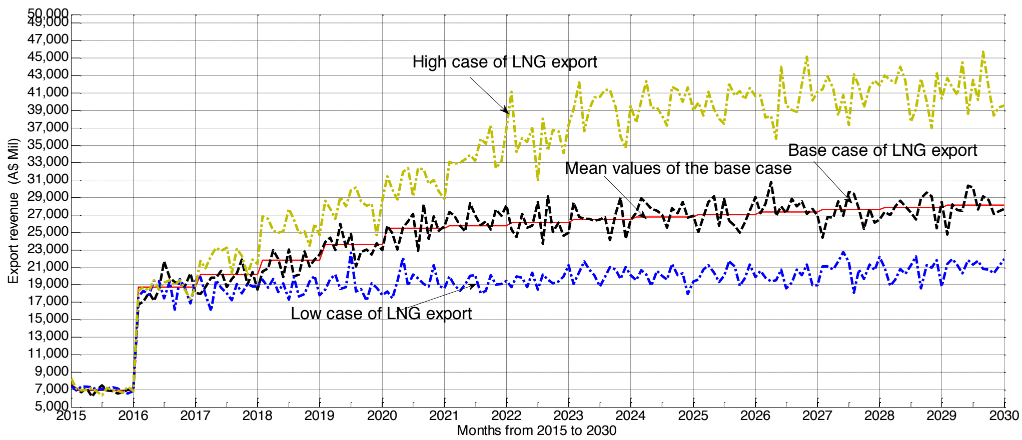
This section projects LNG export revenue based on the IES (2013). Figure 13 presents the high, low, most likely values of export revenues for three different scenarios of LNG prices. The values of export revenues for all scenarios of LNG prices in 2020 are ranged from A$19 billion to A$33 billion. By 2030, the values of export revenues for all scenarios of LNG prices are ranged from A$21 billion to A$27 billion. In average the differences in the most likely values of export revenues are up to A$12 billion. However, the differences between low case of export values (A$ 21 billion for Scenario 3) and high case of export values (A$ 39 billion for Scenario 1) could be up to A$18 billion dollars. That suggests the future export revenues are varied significantly by different scenario of LNG prices.

Figure 13: Case 2: projection of export revenues

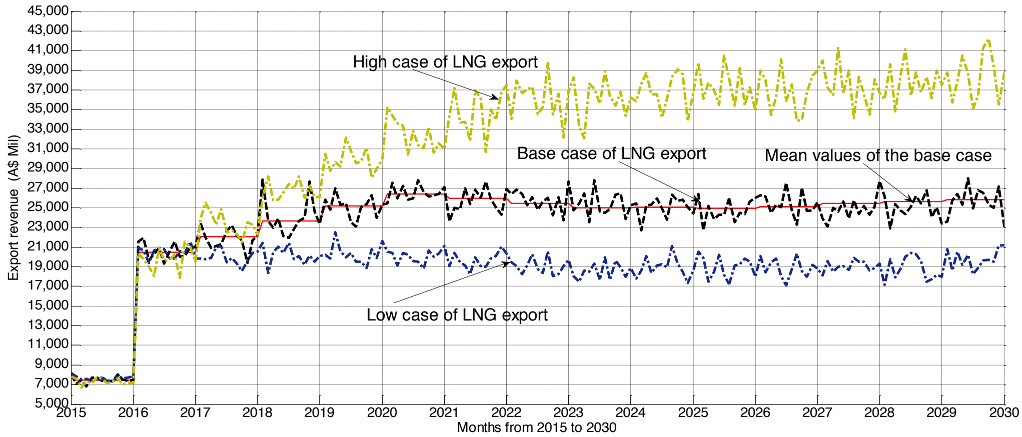
a) Scenario 1 of LNG prices



b) Scenario 2 of LNG prices



c) Scenario 3 of LNG prices



Note: Prices are at 2014; Exchange rate for 2014 is provided from Reserve Bank of Australia (2014);
- Sources for long term crude oil prices used for scenario projection of LNG prices: ***Scenario 1****: the Institute of Energy Economics (IEEJ 2014),* ***Scenario 2****: the US Energy Information Administration (EIA 2014a); and* ***Scenario 3****: the World Bank (WB 2014b).*

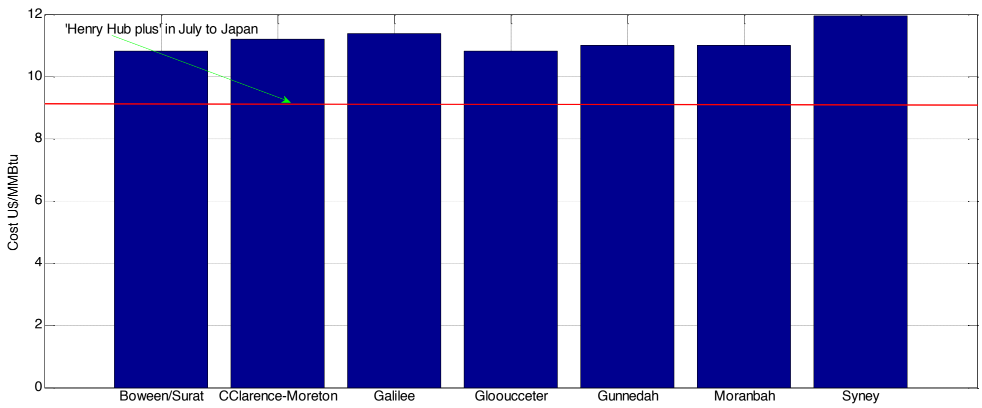
6. Australia's domestic issues for LNG expansion

Despite the brilliant outlook of LNG expansion and export revenues, a number of domestic issues could influence future LNG development as well as export revenue in eastern Australia. According to the Department of Industry (2014), these challenges include high cost structures; slower construction times, need for large capital investments; lack of experience; uncertainties over LNG availability and reliability; and high uncertainty over the cost of developing new gas. The effect of LNG exports on domestic gas users is also important.

6.1 High costs of new LNG development

The high cost of CSG development is also a major challenge for Australia in the Asia-Pacific region. Based on McKinsey and Company (2013), the cost of building new LNG projects in Australia is now about 20–30 per cent higher than in North America and East Africa. Figure 14 shows the delivery prices of CSG (for 2P reserve) by different basin in Australia and the 'Henry Hub plus" price in Japan.

Figure 14: Delivery price of Australian new CSG and 'Henry Hub plus' price in Japan



Source: Intelligent Energy Systems (2013), Argus (2014); Own calculation.

LNG delivery prices of Australian CSG basin in the eastern market are all higher than the 'Henry Hub plus' price to Japan. The high cost of new LNG based on CSG is a comparative disadvantage for the eastern Australia's LNG development.

6.2 Risks of LNG production based on coal seam gas

Based on the Core Energy Group (2013), the major risks of CSG development include a production ramp up, development schedules and needed infrastructure. Each plant in Gladstone used a Conocophillips "Cascade" process which can operate at low capacity factors. For example, BG has stated that the QCLNG project will take 18 months to match the build-up in CSG production. Santos has stated that it will take Train 2 at GLNG 2 to 3 years to reach full production.

There is a risk of a significant impact on water resources caused by one or more CSG-based LNG developments. Factors which may directly or indirectly bring about a significant impact on water resources could include a change in the quantity, quality or availability of surface or ground water. In 2013 the Federal Government introduced an amendment to Australia's National Environment Law, such that water resources are a deemed a matter of national environmental significance, which must be considered as part of CSG developments (Core Energy Group 2013).

There have been some delays in the upstream (gas production) component due to: land access flooding; delays in negotiating access agreements with landholders; and a greater number of wells required than initially forecast. Development of infrastructure is important and can influence future LNG development The Core Energy Group (2013) also recognises that there is scope to physically deliver gas in the eastern market. However this involves significant transport costs and in many cases there are capacity restrictions on orderly flow and/or will require enhancement to infrastructure to facilitate flow of large volumes.

6.3 Other domestic issues

Under trade liberalisation, the effects of LNG development on domestic gas users are important, including the convergence of low domestic gas prices towards the Asia-Pacific LNG market price. Higher prices under free gas trade in the Asia-Pacific, however, may decrease gas consumer welfare. Domestic consumers will be worse off from higher prices and added uncertainty over gas supplies. Large domestic gas users, including those who demand significant power from electricity generation, along with manufacturing and mining industries, will also face higher prices, less security over long term contracts and more uncertainty over gas supplies generally. Domestic gas users will also be worse off from higher gas prices (details of the analysis are provided in Che and Kompas (2014c)).

7. Remarks

Australia is and will rapidly become the biggest LNG exporter in the world over the next few years. Links to the international LNG market implies eastern Australia's LNG export revenue will depend on future LNG prices in this region. Based on the analysis of LNG pricing formation and the projection of LNG prices in the Asia-Pacific region, along with Australia's LNG netback prices in Che and Kompas (2014a), this paper projects eastern Australia's export revenue based on different scenarios of LNG prices in the Asia-Pacific and future LNG production. Two different cases of eastern Australia's future LNG exports with low, medium and high values are analysed. The first case of future LNG export is based on the 7 train Core case based on the AEMO (2013 and 2014) and the 7 train by the Core Energy Group (2013). The second case of future LNG export is based on the IES (2013). For the first case, export revenues for all scenarios of LNG prices range from A$17 billion to A$23 billion by 2020 and A$21 billion to A$27 billion by 2030. For the second case, export revenues for all scenarios of LNG prices are range from A$19 billion to A$33 billion by 2020 and A$21 billion to A$39 billion by 2030.

Along with tremendous opportunities, the obstacles facing the eastern Australia's LNG expansion are significant. These obstacles include high cost structures; slower construction times and needed large capital investments; lack of experience; uncertainties over LNG availability and reliability; and uncertainty for developing new gas. The effects of LNG trade on domestic users are also important.

Appendixes

Appendix A: Abbreviations and units

Abbreviations

2P	proved and probable (reserves)
3P	proved, probable and possible (reserves)
2C	contingent (resources)
AEMO	Australian Energy Market Operator
BP	British Petroleum
CSG	coal seam gas
EIA	Energy Information Administration
FEPC	Federation of Electric Power Companies of Japan
GIIGNL	International Group of Liquefied Natural Gas Importers
IGU	International Gas Union
IEA	International Energy Agency
IEEJ	Institute of Energy Economics
IES	Intelligent Energy Systems
JCC	Japanese Custom Cleared price
JPDA	Joint Petroleum Development Area
METI	Ministry of Economy, Trade and Industry of Japan
OECD	Organization for Economic Cooperation and Development
PAJ	Petroleum Association of Japan
RBA	Reserve Bank of Australia
WB	World Bank

Units

Mbcm	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	PJ
MMBtu	million British thermal units

Appendix B: Econometrics analysis of structure and dynamics of LNG pricing in the Asia-Pacific

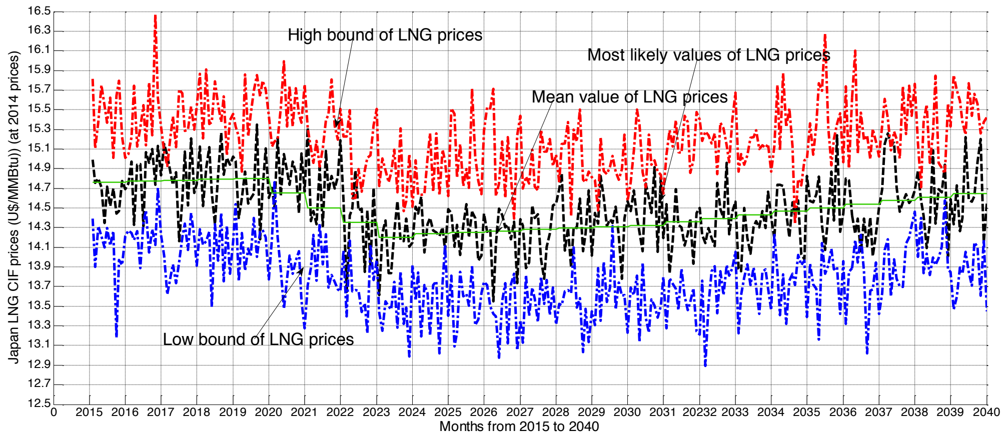
This appendix is extracted from Che and Kompas (2014a). The tests of structural breaks and cointergration based on Chow test (Howard 1989) and Unit root test (Fuller 1996 and Enders 2010) are carried out for the econometric specification. The econometric specification of structure and dynamics of LNG prices for a time period of JCC prices is given by

$$P^{LNG}_{i,T,t} = \delta_{i,T} + \alpha_{i,T,t} P^{JCC}_{i,T,t} + D_{i,T,s} + \zeta \qquad \text{(B1)}$$

where i presents different ranges of JCC prices; T presents different structural period; t is time in the period T; and s present geopolitical and economic events in T; $\delta_{i,T}$ is the base part of LNG prices; D_k is the dummy variable for geopolitical or stochastic events; and ζ is the error term of the regression.

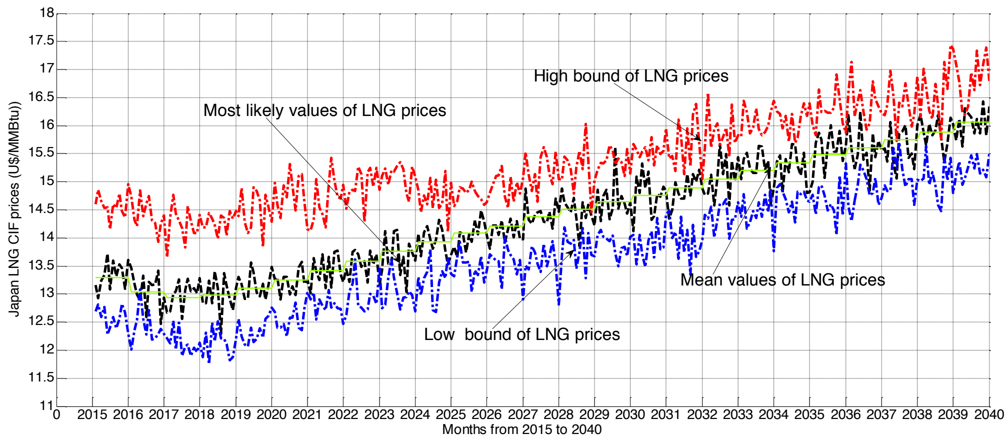
The econometric regressions for Equation (B1) are estimated based on four different price ranges and three different time periods, including the period of 8/1989 to 12/2002; the period of 1/2003 to 12/2007; and the post 2008.

Figure B1: Projection of Japan LNG CIF prices, 2015–2040: Scenario 1
(U$/MMBtu at 2014 prices)



Note: Projection of crude oil price is from the Institute of Energy Economics of Japan IEEJ (2014).

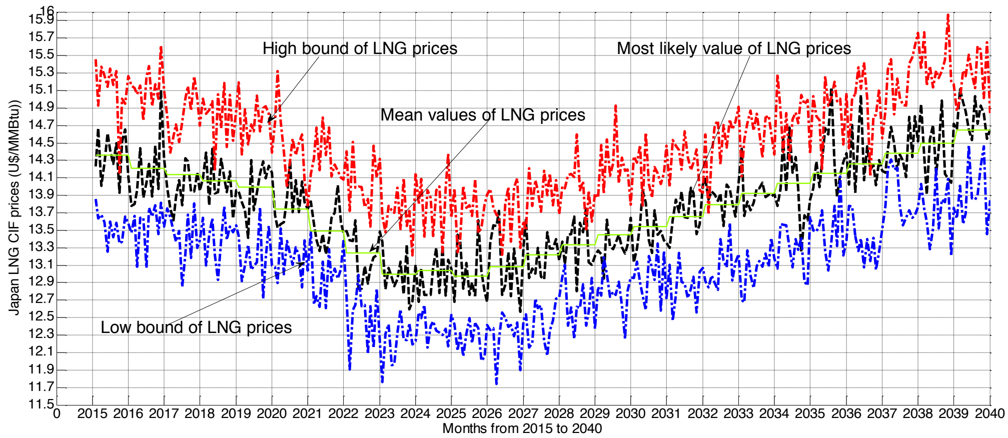
Figure B2: Stochastic projection of Japan LNG CIF prices, 2015–2040: Scenario 2
(U$/MMBtu at 2014 prices)



Note: Projection of crude oil price is from the US Energy Information Administration (EIA) (2014).

Figure B3: Stochastic projection of Japan LNG CIF prices, 2015–2040: Scenario 3

(U$/MMBtu at 2014 prices)



Note: Projection of crude oil price is from World Bank (2014b).

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