Economic Analysis and Policy 59 (2018) 103–112

Contents lists available at ScienceDirect

Economic Analysis and Policy

journal homepage: www.elsevier.com/locate/eap

Recent Trends in Economic Research

East-coast Australian gas markets—Overcoming the lumpiness of capital allocation and temporal instability

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ARTICLE INFO

Article history:
Received 11 February 2018
Received in revised form 14 May 2018
Accepted 14 May 2018
Available online 23 May 2018

JEL classification:
D04
D47
Q40
Q41
Q48

Keywords:
Energy
Gas markets
LNG
Partial equilibrium

ABSTRACT

Australia's east-coast gas market has undergone significant transformation in the past decade. The discovery of non-conventional coal-seam gas reserves led to investment in three 'lumpy' LNG export facilities in Gladstone, Queensland. Drilling activity has subsequently slowed, a direct result of a soft global price for LNG. This slowdown, in an environment of a tripling of east-coast gas demand, has resulted in concerns about domestic gas shortages. To be clear, there is no lack of gas resources. Instead, the problem relates to the relative lumpiness of capital allocation and temporal instability driven by changing global circumstances. Utilising a simple partial equilibrium model, various options for overcoming these problems are analysed. Of these options, developing import infrastructure appears to be a 'no regrets' option that would ensure that the price floor, the LNG netback price, also becomes the market price cap.

1. Introduction

The Australian east-coast gas market has been transformed by the development of significant 2P[2] coal-seam gas reserves and a Liquefied Natural Gas (LNG) export industry in Queensland. Domestic east-coast gas pricing is now linked to international LNG pricing for the first time. There are now persistent concerns about potential gas shortages, higher domestic gas prices and unavailability of supply contracts with reasonable tenors (see AI Group, 2017, and De Silva et al., 2016). Simshauser and Nelson (2015a, b) concluded that the east-coast of Australia could face 'unmet gas demand' from 2016. More recently, the Australian Energy Market Operator (AEMO) concluded that gas shortfalls of between 54 Petajoules (PJ) and 107 Petajoules (PJ) per annum (up to around 15% of domestic demand) could occur from 2018 (AEMO, 2017).

At least five alternative 'solutions' have been proposed over several years: the introduction of an east-coast domestic gas reservation policy; utilisation of a 'National Interest Test' for new LNG export projects; expanding domestic gas supply through the removal of moratoria on coal-seam gas extraction; developing pipeline capacity 'linking' the east-coast and west-coast gas markets; and construction of LNG import facilities. Neill (2017) comprehensively demonstrates the net economic costs associated with the introduction of a domestic gas reservation policy. A 'National Interest Test' is worth

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[2] 2P is an industry term used to denote gas that is likely to be extractable given existing technology and commercial circumstances.

https://doi.org/10.1016/j.eap.2018.05.002
0313-5926/

Table 1
Australian east-coast reserves.
Source: AEMO (2017).

Category of reserve	Reserves (PJ)
Developed 2P	10,151
Undeveloped 2P	39,166
2C	56,429
Potential resources	151,867

Table 2
East-coast LNG projects.[a]
Source: Industry reports.

Project	operator	Project announcement	Max. capacity (PJ/annum)	Contracted supply (PJ/annum)	Train 1 commissioning	Train 2 commissioning
QCLNG	Shell	Oct 2010	549	474	Dec 2014	Jul 2015
APLNG	Origin	July 2011	575	510	Jan 2016	Oct 2016
GLNG	Santos	Jan 2011	498	427	Sep 2015	May 2016
Total			1622	1411		

[a] One further project, utilising Arrow's CSG reserves, was also proposed but ultimately shelved. See http://www.smh.com.au/business/shell-shelves-arrow-lng-project-in-queensland-20150129-131sqe.html, accessed online 17 November 2017.

considering but is unlikely to have any impact in the medium term given no new LNG export facilities are being considered on Australia's east coast.

For the purposes of this article, the 'problem' facing policy makers is overcoming limitations of domestic gas supply on Australia's east-coast. Potential solutions need to be assessed for their robustness in environments of both comparatively high *and* low international LNG pricing as outcomes are not uniform in these two pricing scenarios. The purpose of this article is therefore to consider: the Australian Domestic Gas Security Mechanism; expanding domestic supply; linking the east-coast and west-coast markets by pipeline; and the development of LNG import capability as potential solutions to shortfalls of natural gas supply in the east-coast market, in scenarios of both comparatively high and low international LNG pricing. Section 2 provides a quantitative overview of the problem facing the east-coast gas market. Simple partial equilibrium theory is presented in Section 3 to critically assess potential solutions. The various proposed solutions are considered in Section 4 with concluding remarks and brief policy recommendations provided in Section 5.

2. Overview of the problem

At the turn of the century, there was concern that Australia's east-coast would suffer significant shortfalls of natural gas.[3] But with the development of new drilling technologies, large resources of coal-seam gas were unlocked and 2P reserves increased substantially from 3400 PJ in 2005 to approximately 49,300 PJ today. With historical annual domestic gas demand of around 600–700 PJ per annum, the ratio of 2P reserves to domestic demand increased substantially from around 5 years to 75 years of supply. An overview of reserves is presented in Table 1.

As a consequence of the development of such significant gas reserves, three large LNG export facilities were developed at Gladstone in Queensland. The projects are known as QCLNG, APLNG and GLNG. These facilities can consume around 1450 PJ per annum. Around 95% of the rated output of the LNG trains is forward contracted and the contracts are understood to be at least 20 years in length.[4] Over this period of operation, this is expected to result in around 30,000 PJ of gas consumption. It should be noted that this development was a rational economic response to the existence of such vast quantities of reserves compared with relatively small domestic demand. It represented the only way of monetising the reserves in a timely manner. A summary of the LNG projects is presented in Table 2.

The development of an LNG export industry has resulted in a tripling of annual demand for natural gas and produced $120 billion in investment across Australia (see Jacobs, 2011 and Christie et al., 2011). But there is now concern about potential gas shortages and significant public commentary about high prices driven by supply scarcity. However, it is important to note that the issues largely relate to the lumpiness of capital allocation and temporal instability. In this author's view, concerns should not relate to where there are sufficient resources to meet demand.

Australia's very significant east-coast gas resources are shown in an aggregate supply curve in Fig. 1.

Fig. 1 shows an aggregate gas supply curve for east-coast Australia. There is more than enough gas to *physically* satisfy domestic demand and current LNG export contracts for at least twenty years. There are around 50,000 PJ of 2P reserves with

[3] In fact, considerable investment was made on front-end engineering and design (FEED) for a pipeline to connect vast reserves of natural gas in Papua New Guinea to the east-coast Australian market.

[4] QCLNG has contracted its gas to CNOOC, Shell, Tokyo Gas and Chubu Electric. GLNG has contracted its gas to Petronas and Kogas. APLNG has contracted its gas to Sinopec and Kansai Electric. GLNG has indicated that it will only be producing around 85% of its contracted volume until the 2020s (see Chambers, 2017). It is understood that QCLNG has more flexibility as its contracts are supplied from the Shell LNG portfolio, rather than being directly linked to the QCLNG project.