TAXATION AND PRICING OF NATURAL GAS: THE DUTCH TRANSITION TO A GAS HUB AND LESSONS FOR AUSTRALIA'S INTEGRATED GAS PROJECTS

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Overview

Currently Asia-Pacific region suppliers of LNG (Australia, Malaysia and Papua New Guinea) and their customers in East Asia (China, Japan and Taiwan) negotiate gas prices under the Japanese Crude Cocktail (JCC) oil-indexed long term contracts (Roger and Stern 2014). As the region lacks a transparent LNG pricing benchmark, there is a fundamental reliance by customers on such contracts to guarantee security of supply — and by suppliers — to ensure they get a reasonable return on their gas project investment, including coverage of taxes. Nonetheless there is considerable academic literature that canvasses the establishment of a market hub for gas pricing in the Asia-Pacific (eg. Vivoda 2014, NERA 2016, Nikhalat-Jahromi et al. 2017, Kim 2017, Sung 2017). The discourse on future improvements to the Asia-Pacific LNG export market is dominated by calls from East Asia customers for greater transparency in gas price setting.

As Australia is a major exporter of gas, its government is cautious about fostering the development of a gas hub market, as the value of feedstock gas used for liquefaction is a factor in the calculation of the tax base to determine the petroleum rent tax revenue. A rent tax is applied to petroleum (oil and gas) projects in locations under Australian jurisdiction (*Petroleum Resource Rent Tax Assessment Act 1987).* A rent tax, which is a type of royalty, is a secondary tax that targets above-normal profits or economic rent from a resource. In Australia, multinational companies operate mega-integrated gas projects that extract gas and liquefy the feedstock gas into LNG, which is transported by tanker to export customers. Typically there is an absence of an arms-length sale price for feedstock gas in an integrated project. Thus for gas projects in Australia, corporate taxpayers are required to use the gas transfer price (GTP) methodology detailed in government regulations to determine feedstock gas prices. In essence, the regulations use the Net Back and Cost Plus pricing methods allowed by the OECD (2017), however we argue that in practice, the prescribed use of the methods in combination to derive an average price for the GTP negatively affects the government's tax base.

There is a gap in the literature to consider the perspective of Asia-Pacific exporter countries in the general call for greater transparency in gas prices. In order to close this gap we analyse the successful transition by the Dutch from mechanistic gas pricing to market hub gas pricing for their Groningen gas fields, and possible lessons for Australia's transfer pricing problems in integrated gas projects.

In this paper questions are asked about the Dutch experience in moving to a market hub price and about possible outcomes if Australia's petroleum tax regime's gas transfer pricing regulations for integrated projects were to be replaced by gas market hub pricing. First we closely analyse the Dutch experience in transformation of its pricing policy. For the second question, we use data from the four largest, integrated, gas-to-liquids projects off the north-west coast of Australia. Using economic data from these projects, we analyse several fiscal scenarios with the FARI model of the International Monetary Fund's (IMF). FARI stands for Fiscal Analysis of Resource Industries (FARI) model, which is *Excel*-based and primarily used for work on fiscal regime design, as well as for revenue forecasting.

This research builds on a previous case study (Kraal 2017) that concerned the modelling of resource taxation design changes to the Chevron-operated *Gorgon LNG* project, an integrated natural gas operation off north-west Australia. For this current research, three additional integrated gas projects in Australia are modelled. Together the four projects should provide firm empirical evidence about transparency and revenue differences between a gas transfer price regime and a market hub price. This empirical research is limited to Australia's dominant offshore petroleum projects (in terms of gas production per annum). Two of the projects have commenced extraction activities, while the other two will commence production in 2018. The petroleum is from basins in waters under Australian federal jurisdiction.

Methods

The research aims to draw on the lessons from the Dutch transition to gas market hub, and explore an alternative of establishing a market hub price for natural gas extracted in Australia, which is currently subject to gas transfer pricing. In order to assess the Dutch experience in establishing a market hub gas price, we gather data from the Dutch reform, from a regulated calculation of gas transfer prices to a market hub price. The method is to produce a narrative to provide insights about the economic and legislative issues faced by government and industry before, during and after the transition to a market hub. The outcomes will generate guidelines for reform that could be replicated in other jurisdictions, such as Australia.

In order to determine the consequences of replacing Australia's petroleum tax regime's transfer pricing regulations for integrated natural gas-to-liquids (GTL) projects by market-hub gas pricing, we use the method of fiscal system modelling. The term GTL is used to describe the activity where the commercial focus is on extraction of gas for conversion into liquid form — for the purposes of export. The method of fiscal system modelling is appropriate to gather revenue and iterative data for the transition in the pricing system. In this exercise, we analyse a number of scenarios: firstly, the current fiscal regime with gas transfer pricing, and secondly, a fiscal regime with a notional market hub price inserted to replace the gas transfer price. The model scenarios are compared and the one that presents the most transparent revenue results is discussed in terms of the challenges of legislative change within the framework of energy justice.

The model is applied to four integrated gas projects in Australia. The selected gas-to-liquids projects are Inpex's *Ichthys LNG*, Woodside Petroleum's *Pluto LNG* and Chevron's *Wheatstone LNG* and *Gorgon LNG*. The project economics data used for modelling is proprietary from Wood Mackenzie, a reputable and internationally recognised data collection/analyst organisation. The latest 2017 data across the four selected projects is used. Production data inputs to FARI include volumes of export and domestic gas, and condensate. Expenditure includes exploration, capital and operating costs.

This research adapts the energy justice framework for the Australian gas sector for use as a tool to assess the costs and benefits of moving toward more equitable gas pricing. Energy justice might be seen as a variation on the triple-bottom line concept (political, social and environmental) advocated previously for the extractive projects (Kraal and Nash 2010).

Results

We find that that the total tax revenue under a Net Back market price for the four GTL projects would be US$15.5 billion over the years 2012 to 2030, compared to US$5.5 billion under the regulated gas transfer price (GTP). It appears that the GTP method is flawed showing an average price of only US$4.81/mcf — compared to an average Net Back market price of US$6.47/mcf. In addition, the GTP method lacks transparency as it can be manipulated.

Conclusions

Clearly, a move to a more accountable Net Back market price as the basis for feedstock gas prices is more desirable, as the gas price is a key factor in the calculation of the tax base to determine the petroleum tax revenue to government. A market price has an element of due process as opposed to the asymmetry of knowledge embodied in the behind-the-scenes calculation of a GTP by a commercial gas supplier.

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