Natural gas in Brazil: a challenging market landscape

Ieda Gomes

The Brazilian energy matrix is much diversified. Renewable energy accounts for more than 40 per cent of the primary energy offer, in the form of hydroelectricity and biomass – wood, charcoal, and sugarcane products. The bulk of electricity, 76 per cent, is produced by hydroelectric power plants. Brazil produces 2.2 million barrels per day (mb/d) of oil, most of which is consumed in the domestic market. Natural gas accounts for 12 per cent of the primary energy offer.

In 2013 Brazil produced 28 billion cubic metres per year (bcm/year) of natural gas, of which 73 per cent is associated. Domestic production has been growing steadily; by the end of 2014 domestic production is expected to reach 31 bcm/year, a growth of 11 per cent when compared to 2013. However, half of the domestic production is consumed in Petrobras operations: reinjection, oil field and pipeline operations, refineries, and Petrobras' own power generation. Local gas distribution companies (LDCs) market gas to all consumers in their exclusive geographic franchise areas.

'… THE BRAZIL MARKET IS IN THE SAME LEAGUE AS SPAIN AND THE NETHERLANDS.'

As of August 2014, natural gas consumption reached an average 99.2 cubic metres per day (36 bcm/year) including Petrobras refineries and own power consumption, so the Brazil market is in the same league as Spain and the Netherlands.

Brazil is a net gas importer, with an average 54 million cubic metres per day (mcm/day) imported via the 3000 km Bolivia–Brazil pipeline and three floating LNG terminals (FSRU). LNG imports started in 2009 and have been ramping up since then due to a very long dry period which has drastically reduced the storage availability in the main south-east and north-east hydro reservoirs. In 2013 Petrobras imported 3.72 million tonnes per annum (mtpa) of LNG; imports in 2014 are likely to be higher, already totalling 2.8 mtpa by end August 2014. Petrobras owns most of the gas-fired power plants and only imports LNG when the national power system operator (ONS) orders the dispatch of thermal capacity. The period 2012–14 has been atypical, with some plants operating as baseload. Therefore the purchase of LNG is done via spot and short-term contracts, with Brazil commanding prices similar to those seen in north Asia. In 2012 LNG represented only 11.4 per cent of the gas supply, whereas in 2014, it accounts for 20.2 per cent.

Natural gas demand in Brazil is becoming unpredictable

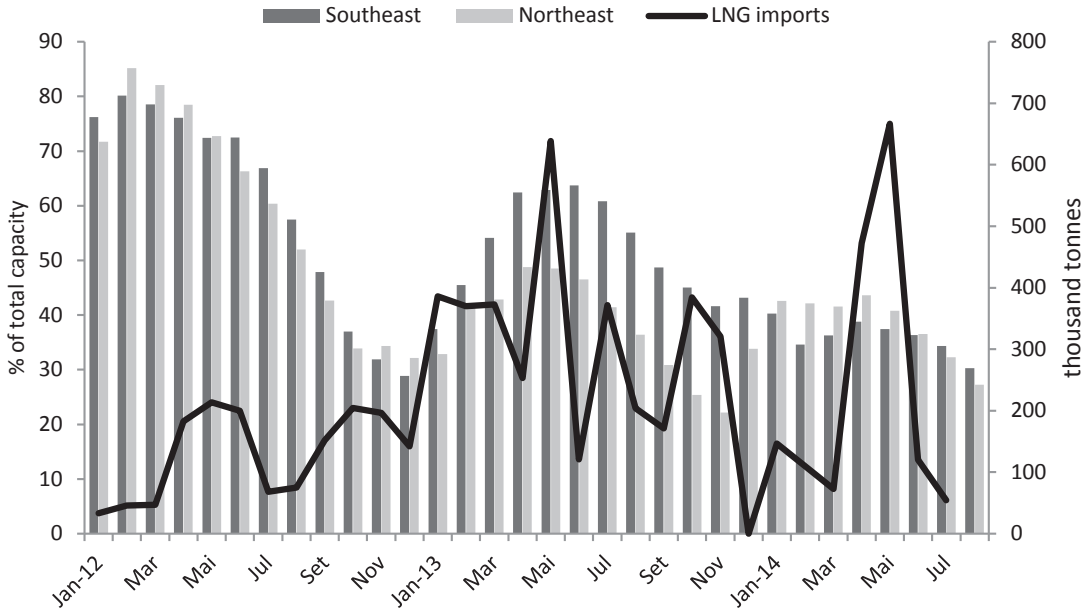
Brazil's gas market is unique when compared to other emerging countries, both in terms of market share and as regards the regulatory model. Until 1995 Petrobras had a legal monopoly on hydrocarbons exploration, production, and transportation. A constitutional amendment followed by the 1997 Petroleum Law and the 2009 Gas Law established the terms for private participation in the oil and gas sector in Brazil. Today any company established in Brazil can explore for, produce, transport, import, and export hydrocarbons, and also build LNG terminals and power plants. However, Petrobras still enjoys a de facto monopoly in gas infrastructure and is also the largest owner of gas-fired power plants. On the distribution side, Brazilian states grant exclusive 30–50 years geographical franchises to local distribution companies (LDCs) whose business models are dictated by the state government; some of these companies are totally private while others are state-controlled companies in partnership with Petrobras and private companies.

There are two levels of regulation: the National Petroleum Agency (ANP) regulates upstream and midstream activities, whereas state agencies regulate gas distribution and end-user gas prices. Some market players complain about the perceived lack of harmonization between the federal and state regulators.

There are states where large industrial and power consumers can buy gas directly from producers, but they have to pay a distribution fee to the LDCs; also since there are no other competing gas suppliers, large consumers are very reluctant to become free consumers.

Until 2011, industrial consumers accounted for 67 per cent of gas sales in Brazil, but the increased dispatch of gas-fired power plants has changed the landscape. In 2014 the power sector accounts for 47 per cent of the gas marketed in Brazil.

Industrial sales, once the backbone of the Brazilian gas market, have been



LNG imports vs hydro reservoirs capacity

stagnant since 2011. The growth of gas demand had originally been underpinned by the substitution of gas for high sulphur fuel oil (HFO), but the potential for additional HFO substitution is now quite small – only 9 mcm/day – and limited to regions in the far north and north-east which do not have pipeline infrastructure.

'… THE GROWTH OF THE NATURAL GAS MARKET IN BRAZIL IS PREDICATED ON THE GROWTH OF THERMAL POWER GENERATION.'

The other market segments – transport, commercial, and residential – are constrained by competition with subsidized LPG and petrol. The mild weather in most Brazilian regions is a barrier for traditional residential gas applications, such as space heating and hot water. The cost of building infrastructure in large cities is also high and time-consuming, due to a complicated permitting process.

Therefore the growth of the natural gas market in Brazil is predicated on the growth of thermal power generation.

Based upon their long-term electricity demand forecast, the Ministry of Mines and Energy (MME) conducts annual auctions for power plants which are due to operate within five years, the so called A-5 auctions. The Ministry fixes the variable cost of operation (CVU), which will be paid when the plants operate; the bidders must bid a price below a ceiling composite price, the 'ICB' which should theoretically remunerate capital and other fixed costs including the take-or-pay of the gas contracts. Gas-fired power plant investors need to satisfy the Ministry that they will sign 25-year gas supply agreements and, in the case of domestic gas, that the gas reserves are sufficient to underpin such long-term gas contracts.

Due to its extensive portfolio, Petrobras is currently the only gas producer which could meet such criteria. However, it has not been in a position to commit to supply any private power generation project and it also seems to be willing to save its domestic gas for its own power plants. Currently there is only one independent gas-cum-power project in north-east Brazil; this monetizes gas from an onshore non-associated gas field in the northern state of Maranhao to a group of 852 MW power plants.

Due to the lack of domestic gas, independent power developers have been trying to develop projects based on LNG. The Ministry defined the CVU and ICB for the upcoming A-5 auction at, respectively, BRL 250/MWh and BRL 197/MWh (equivalent to US$113/MWh and US$89/MWh) in September 2014. However, in the wake of the results of Brazilian elections, the Brazilian Real has depreciated significantly and as of 14 November 2014, the prices have dropped to US$96/MWh and US$76/MWh, respectively. The power investors believe that they would need regasified LNG prices of US$11–13/MMBtu at the plant gate to be able to dispatch at a US$113/MWh CVU. These prices are indeed below the current level of LNG prices being negotiated on long-term contracts.

The power auction criteria allow for LNG prices to be indexed to either Henry Hub (HH) or Brent, but although HH-indexed prices are currently more competitive than Brent-indexed prices, the fixed-price component of the US-based projects plus shipping and regas costs, are much heavier than the variable HH component. Due to the unpredictability of the plant dispatch in Brazil, the investors would have to build all fixed costs into the ICB, which is currently insufficient to allow for the remuneration of all fixed costs.

In order to overcome the constraints of the volatility of the demand and the low auction price levels, LNG suppliers and power investors will need to develop creative price formulae and very flexible LNG contracts. These constraints will probably be a huge impediment for independent LNG-cum-power projects, unless the MME allows for realistic power prices which take into account the market prices and take-or-pay obligations for LNG. In the meantime electricity prices in the spot market are currently sky high, circa US$300–350/MWh in October 2014.

The need for gas-fired power plants is becoming more pressing, because the environmental permitting process makes it almost impossible to build hydro power plants with reservoirs; suitable back up plants should thus be developed as a matter of necessity. As power demand continues to grow, government forecasts have identified the need for 48 GW of additional power capacity between 2013 and 2022, of which only 1.85 GW is gas-fired and 9 GW wind. Only 7 GW of reservoir capacity will be added in the same period.

What it the outlook for 2020?

Brazil is home to a massive investment programme to develop its upstream oil resources, most of it on ultra-deep water frontiers, particularly from pre-salt blocks. According to industry and government sources, Petrobras and international and local oil companies will need to invest US$40 billion per annum in offshore E&P until 2022 to deliver production goals of 4.2–5 million barrels of oil per day. A significant volume of associated natural gas should be produced in this horizon, but there is uncertainty about the actual gas to be available to the market. The key questions concern the volumes needed for reinjection, the high content of carbon dioxide

(ranging from 10 to 40 per cent), and the cost of infrastructure to deliver gas to the shore. The industry is projecting that the domestic gas offer will nearly double from current levels to 86 mcm/day (31 bcm/year) by 2020. Petrobras has planned for three evacuation pipelines, aiming to connect some pre-salt blocks to the markets in the states of Rio de Janeiro and Sao Paulo, with total capacity of 50 mcm/day. One of the pipelines is already in operation and the other two are still being procured, with commissioning expected by 2016–17. It is still unclear what additional infrastructure will be required to deliver the remaining 36 mcm/day to the market.

Despite the significant increase in domestic gas supply, Brazil will continue to be dependent on Bolivian gas and LNG imports. Unless the government changes the power auctions rules, allowing for firm thermal power dispatch, Brazil will need to rely on 8.5–10 mtpa of flexible LNG supplies, which will be very costly. At current prices, regasified spot LNG costs US$17–20/MMBtu, whereas legacy power plants pay only US$4.6/MMBtu for their gas supplies.

'THE LEAST-COST ALTERNATIVE FOR BRAZIL IS TO DEVELOP ITS OWN DOMESTIC GAS RESOURCES …'

The least-cost alternative for Brazil is to develop its own domestic gas resources, as less than 5 per cent of the country's extensive sedimentary basins have been effectively developed. In order to do this, the government needs to contribute towards de-risking natural gas exploration and development, to attract private investors. This can be done by: promoting additional geological surveys, improving the terms and conditions for the E&P auctions (for example, lower signature bonus and royalties for gas fields), promoting the monetization of independent producers, and reducing market and infrastructure risks by ensuring attractive conditions for the building of new pipelines.