A Natural Fit

Electricity-Gas Integration Challenges in South America

SOUTH AMERICA IS ONE OF THE MOST DYNAMIC regions for the joint development of natural gas and electricity. Gas is abundant in the region, although unevenly distributed (see Figure 1), with significant new reserves projected in Brazil (in its Pre-Salt basins) and in Argentina (shale gas). Unconventional gas reserves in South America are estimated at 1,430 trillion ft^3.

The region's long-term outlook is generally positive, as abundant energy resources offer ample opportunities for the region to sustain its economic growth and electrification; near-universal access to electricity is expected to be achieved by 2030. The region will remain a net oil, gas, and coal exporter. Colombia and Venezuela will benefit from their sizable coal resources, and

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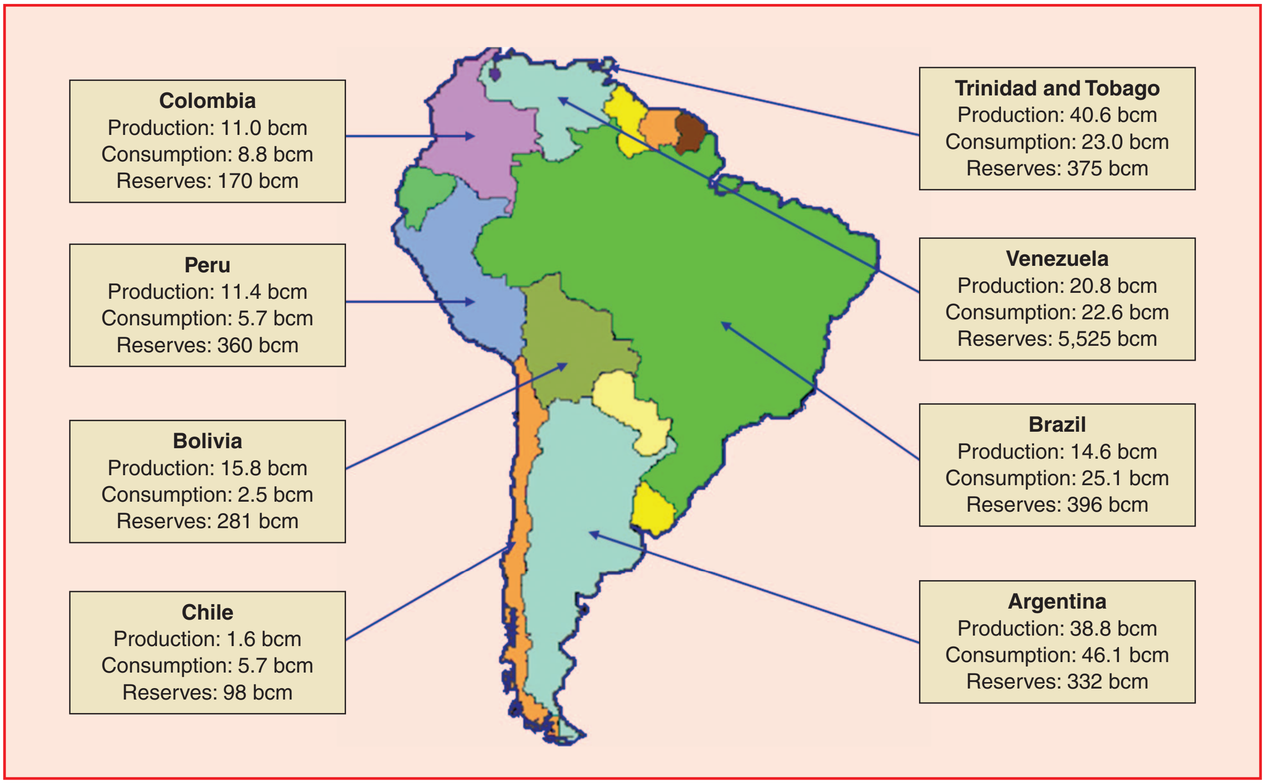

figure 1. Gas production, consumption, and reserves in South America (source: IEA).

Brazil will become the region's largest gas producer before 2025. The region will continue to exploit its hydroelectric resources, with hydroelectricity accounting for more than 60% of electricity generation by 2035—the largest percentage contribution worldwide. Significant growth in solar photovoltaic and wind generation projects is predicted.

The presence of abundant gas resources created active gas industries in countries like Argentina, Bolivia, and Peru in the 1980s and 1990s, changing the energy mix of those countries. Combined-cycle, gas-fired generation plants became an attractive low-cost, low-emissions alternative to coal, displacing other technologies that became less competitive due to low-priced natural gas. This trend also included neighboring countries like Chile, through the creation of an integrated gas network in the region that connected Argentina to Chile, Bolivia to Argentina and Brazil, and Colombia to Venezuela.

That integrated development later failed, however, with major implications for the countries involved. This was largely due to poor gas exploitation and pricing policies. In Argentina, for example, a major gas crisis took place in 2003–2004, leading to the interruption of cross-border supply to neighboring Chile. Despite the abundant gas reserves in Brazil, Argentina, and Venezuela, these countries have become net natural gas importers, and the region has become increasingly dependent on expensive liquefied natural gas (LNG) imports. Nowadays, while Peru exports 18 million m^3 of LNG a day, Argentina imports 30 million m^3 a day, Brazil 41 million m^3, and Chile 16 million m^3. Figure 2 shows the annual imports and exports of natural gas for several South American countries.

Another important element is that the region has a long history of major hydroelectrical development, coupled with the use of coal in thermal generation. While hydro is a low-cost generation source, its massive presence in the region has historically created commercial challenges to the integration of the electricity and gas industries. Power generation plays a key role in the development of new gas fields, but the absence of a firm gas-to-power demand (subject to hydro variability) and the nonexistence of a secondary gas market are incompatible with the typical take-or-pay characteristics of long-term gas contracts. Contracting LNG leaves the countries subject to large gas price variability, and the dimensioning of the required gas volumes is also a major challenge. More recently, with the development of intermittent renewables and the difficulties of building hydro resources with storage, opportunities for natural gas generators have again emerged due to their dispatchability and positive environmental attributes.

This article describes the natural gas resources and infrastructure in Brazil and Chile, their present participation in electricity generation, the applicable gas industry regulations, and the natural gas system's interactions with the electricity sector. It is necessary to compare the economic trade-offs between hydropower and local gas-fired generation. In both countries, hydropower is an expansion option that has lower production costs and higher capital costs for both generation projects and the associated electric transmission. Local gas-fired thermal generation has lower capital costs for both the generators and the electricity network costs, but it has higher production costs along with the capital cost of the needed gas pipelines. In addition, it is relevant to assess how the adequacy of natural gas, electricity, and renewable resources may evolve.

Pricing schemes for natural gas will be discussed, including how the variability of LNG prices affects electricity prices. The article will also address the regulatory and system operation changes made to ease the integration of gas-fired plants and the remaining hurdles to be overcome.

Electricity and Gas Integration in Brazil

Brazil is the largest country in Latin America and an interesting case study of successive attempts to smoothly integrate electricity and gas. The country's experience has been rather mixed, illustrative of the complicated "marriage" between the two sectors.

Despite Brazil's substantial natural gas reserves and the great expectations surrounding the large oil and gas resources located in the Pre-Salt layer (as announced in 2007), the Brazilian natural gas sector is relatively underdeveloped. As demand for space heating is almost nonexistent due to the country's tropical climate, gas demand in the residential and commercial sectors tends to be very limited; the potential demand of the industrial sector (as feedstock for the chemical and petrochemical industry or as a substitute for oil or electricity) has generally been insufficient to justify large investments in gas production and transportation. The electric power sector, on the other hand, represents a major potential market for natural gas, and indeed the demand for gas-fired electricity production has been an important driver behind many of the developments that have enabled the Brazilian natural gas sector to achieve a certain level of maturity today. Today's fairly modest domestic gas production in the country, mostly associated with oil extraction, has been supplemented by pipeline imports from Bolivia since 1999 and by LNG imports since 2007.

The Brazilian electricity sector is noticeably more developed and more complex than its gas sector in terms of physical assets (as illustrated by the contrast between the two transportation networks, as shown in Figure 3), regulatory framework (unlike many countries, Brazil has separate regulatory agencies for electricity and gas), and market structure. The Brazilian electricity market was fully liberalized in 1996, and while oil and gas production was liberalized soon afterward in 1997, regulations regarding gas transportation and pipeline access were only introduced in 2009. Despite the growing private participation in both sectors, the participation of the Brazilian national oil and gas company Petrobras in almost all segments of the natural gas value chain is much more dominant than that of state-owned companies in the electricity sector. In addition, the lack of a robust pipeline network enabling choices among suppliers has made competitive gas pricing difficult to implement. To date, natural gas trading has been carried out chiefly via long-term bilateral contracts.

The complexity of the Brazilian electricity sector has deep historical roots: an intricate system of hydro plants, made up of several river basins and multiple large reservoirs capable of multiyear storage, accounts for 70% of the country's installed capacity. In order to take full advantage of synergies between hydro basins and other complementary sources, the country is fully interconnected at the bulk

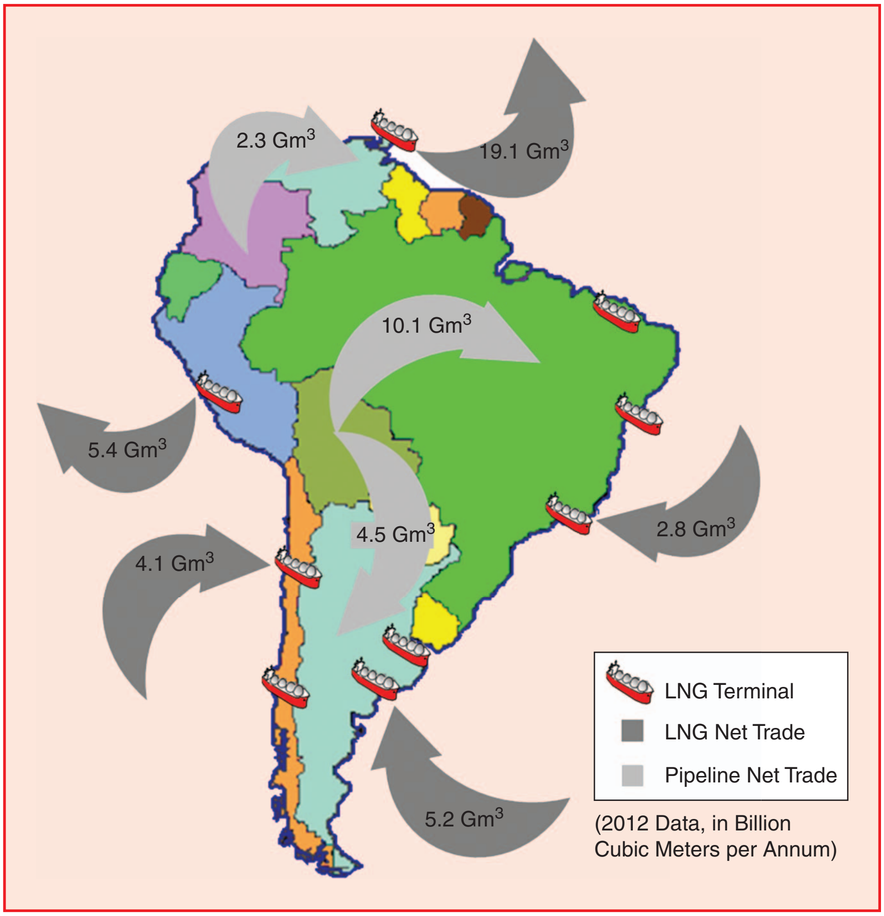

figure 2. Gas imports and exports in South America in 2012 (source: BP).

figure 3. Brazil's (a) gas and (b) electricity networks (sources: Gasnet and ONS).

power level by a 100,000-km meshed high-voltage transmission network, and generation and transmission resources are centrally dispatched by an independent system operator with the aid of stochastic optimization models. Short-run marginal costs—by-products of the dispatch model—are used to set weekly energy spot prices in a wholesale energy market. In order to ensure adequate capacity expansion of around 5,000 MW per year, an auction-based scheme of short-, mid- and long-term contracts has been devised to supply the captive market. As of the end of 2013, the Brazilian power sector reached an installed capacity of 130 GW, a yearly consumption of 530 TWh, and a peak demand of 79 GW. Multiple generation sources are represented in the Brazilian electricity supply, including nuclear, natural gas, coal, cogeneration from sugarcane bagasse, and diesel plants, along with more than 12,000 MW of natural gas–fired generation.

Role of Gas-Fired Generation in Brazil: The Challenge of Flexibility

Even though thermal gas-fired generation remains an important "anchor" for gas consumption, which has the potential to spur production and infrastructure investments on the natural gas side, an interesting question is whether or not the Brazilian electricity sector actually needs natural gas as a fuel. Over the past few years, planned capacity additions have been dominated by wind power and run-of-river large hydro, which have been able to achieve prices as low as US$40–50/MWh; gas-fired generation is generally more expensive than that. Even in a context of inexpensive and abundant renewable candidates for system expansion, however, thermal plants can play two important roles as supporting generation sources:

- ✔ They can function as *back-up generation*, especially during extensive periods of low rainfall.
- ✔ They can function as *dispatchable generation* that can respond quickly to the system's needs. Since environmental constraints have been preventing the construction of new hydro reservoirs at the same time that variable wind and solar power plants have been increasingly participating in system expansion, this contribution is expected to become even more valuable over time.

Both of these functions rely on the operational flexibility of thermal plants, which indeed represents their main contribution in a hydrothermal system. As a consequence, the best usage of available thermal generation resources from the power sector's standpoint would lead to quite a variable production profile, in which long periods of abundant hydro production (and near-zero electricity prices) would be interrupted by water scarcity events during which base-load thermal plants would be dispatched, as illustrated in Figure 4. This behavior, however, is very undesirable from the gas industry standpoint, since the infrastructure of gas production and transportation must be dimensioned for the peak consumption hours and the irregular demand for natural gas makes it difficult to recover the substantial fixed costs involved.

In order to ensure that investment costs will be correctly remunerated, a common practice in the natural gas industry is to use mandatory "take or pay" and "ship or pay" clauses in gas supply agreements (GSAs). On the other hand, accepting such take-or-pay clauses without a secondary market into which to resell the natural gas would translate into physical must-run generation of natural gas plants, reducing these plants' flexibility and hence their attractiveness to the power sector. The conflicting needs of the electricity and natural gas sectors have led to the development of creative solutions for this integration, as well as major clashes and setbacks over the years.

The Integration and Disintegration Years

A jump start of the gas-to-power business in Brazil came in 2000 with the construction of the 3,200-km Bolivia–Brazil pipeline, the longest gas pipeline in South America. The pipeline was originally dimensioned to transport 8 million m^3 per day to serve industrial sector demand, but in 2000 its import capacity was revised upward to the current 30 million m^3 per day in order to supply a large amount of newly planned gas-fired generation. These plants were intended as an emergency response to the critical situation of Brazilian electricity supply at the time (which culminated in electricity rationing in 2001), and power purchase agreements (PPAs) were signed with distribution utilities to ensure their commercial feasibility. These PPAs allowed full pass-through to consumers of the terms of the GSA offered by Petrobras, including oil-indexed gas prices and take-or-pay clauses for 70% of the contracted volume.

The postrationing years, however, saw abundant hydro inflows and reduced consumption (demand did not recover to prerationing levels due to energy efficiency gains that were permanently incorporated into consumers' habits). As a consequence, by the time most of this new gas-fired capacity came online in the 2002–2005 period, the electricity sector had little need for it because hydro generation was sufficient to meet 95% of the load. This situation motivated the gas supplier to relax the take-or-pay clauses of the GSA and divert the surplus gas to other uses. The resulting influx of inexpensive "surplus" gas enabled new firm industrial loads to emerge, and the use of natural gas in vehicles was also promoted. This "overbooking" of firm gas sales ultimately resulted in a massive failure to obey dispatch instructions from the electricity system operator, however, when a dry season hit the country in 2006–2007.

The episode serves to illustrate the large deficiencies in the integration of the gas and electricity industries in Brazil at the time. Because the GSAs signed with both the power sector and the industrial sector generally lacked up-front terms regarding the interruption of gas supply, the decisions about which loads to cut in case of overbooking were made haphazardly, and the penalties applicable to the gas supplier as a result of the imprudent management of these contracts were unclear. This situation motivated several research projects on how to better coordinate the two sectors, with a particular focus on improving the official centralized dispatch models of the electricity sector in order to better represent the limitations in fuel supply and transport, giving a more realistic view of Brazilian long-term system reliability. Ultimately, the power sector was able to assert its position as the first-priority gas consumer, subjecting thermal generators to harsh financial penalties in case of any fuel unavailability and therefore imposing on the gas producer the burden of ensuring a firm gas supply to the thermal power plants in the absolute worst-case scenarios.

In addition, it became clear that domestic gas demand had grown to a point that the available gas supply (including Bolivian imports as well as domestic production from existing and future fields) was insufficient to meet demand while obeying the electricity sector's reliability requirement. As a consequence, Petrobras proposed to build LNG regasification terminals to bridge this gap between supply and demand. This decision triggered a new era of gas and electricity integration.

The Emergence of LNG: Integrating Supply into the Electricity Market

The contribution of LNG to the Brazilian gas supply grew quickly. There are currently three functioning LNG

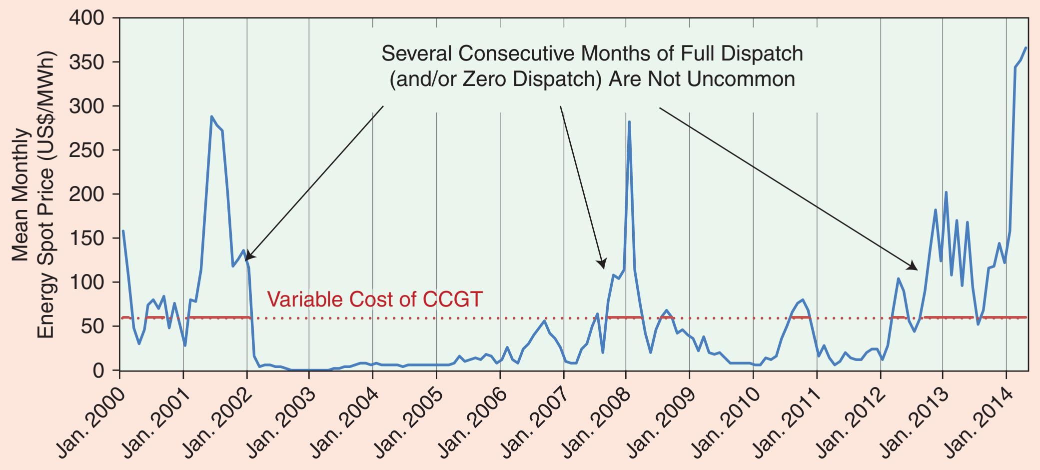

figure 4. The "feast or famine" nature of Brazilian electricity spot prices implies very volatile demand for natural gas (at a stable fuel price).

floating-storage regasification units, with a total import capacity of 40 million m^3 per day. Even though the main motivation for Brazil's move toward LNG was actually the need to ensure the firm supply of existing gas demand, the power sector was quick to identify an opportunity in that alternative gas supply source. While gas pipelines are highly specific investments that connect a specific supplier to a specific point of demand, LNG terminals are more flexible, in the sense that they allow access to a global "network" of producers and consumers. This promises the ability to deliver to the electricity sector a much-desired flexibility in gas supply, through building thermal power plants close to LNG delivery ports and promoting a spot market for flexible LNG delivery or re-exports.

But even though the characteristics of LNG supply seemed to perfectly match the electricity sector's needs, an incompatibility in the regulatory framework created an important obstacle. According to the power sector's prerogatives, gas-fired plants were required to be available to dispatch given only 24 hours' notice from the system operator, an interval that did not allow for adequate procurement of LNG shipments due to sea travel lag times. Although it might have been possible in some situations to purchase spot LNG for immediate delivery by diverting cargo from other destinations, these purchases would not have been reliable and would have involved large premiums relative to typical LNG prices. An interesting debate ensued about how best to integrate LNG into the Brazilian market, given that the preorder of LNG cargos under hydrological uncertainty can induce ex-post "regrets" when an LNG plant is dispatched needlessly or when it remains idle but it should have been dispatched.

One way to manage the variability in LNG demand would be the construction of physical gas storage, which is practically nonexistent in Brazil. But in the abstract at least it was much more attractive to use Brazil's existing hydro reservoirs as energy warehouses or "energy banks" that could enable intertemporal energy swaps, accommodating the various technologies' needs. To exploit this synergy, in 2008 the electricity regulatory framework introduced a creative "virtual storage" mechanism. This mechanism determines that a thermal plant that is not dispatched by the system operator but that elects to generate anyway (for example, because it is already committed with an LNG cargo) can do so by displacing reservoir hydro plants in order of merit, receiving an "energy credit" that is linked to the amount of water that was stored. It was determined that, for accounting purposes, the virtually stored "thermal generation" would be lost first whenever spillages occurred but that hydro plants were not to receive any payment in exchange for providing this service, since the available capacity was essentially idle and augmenting the storage level could not possibly harm hydro production. Taking full advantage of hydro "energy banks" has the potential to greatly improve the system's efficiency by capturing the benefits of international gas price seasonality and optimizing plant maintenance schedules.

In 2011, the stochastic dispatch model was changed in order to better represent LNG-based generators' nonanticipatory constraints and shield them from unmanageable uncertainties. In the enhanced model, LNG plants' dispatch was to be centrally determined by the system operator two months in advance, with no possibility of ex post adjustment, since this lag period was determined to be optimal to minimize gas procurement costs.

Current Obstacles to Full Electricity and Gas Integration

Despite these achievements in promoting a better integration between the gas and electricity industries in Brazil, the role of natural gas in system expansion has been minor. Over the past five years, only two new natural gas plants were contracted in new energy auctions (representing less than 7% of the total planned expansion); both were developed by companies that owned gas assets themselves. Because other natural gas plants have been displaced chiefly by wind power and run-of-river hydro plants in the system expansion, it is likely that the beneficial attributes of thermal plants, such as dispatchability and location factors, are being undervalued in the energy auctions. This situation has led to inefficiencies in energy contracting.

Another issue is that there has been very little compromise between the conflicting needs of the electricity and gas sectors, with the "stronger" electricity sector often imposing its immediate wishes with little regard for their consequences in the natural gas sector. As an illustrative example, each candidate thermal project in an auction for new capacity is required to obtain a letter of commitment from a natural gas producer. This commitment ensures the availability of gas reserves that enable the base-load generation of the thermal plant for 20 years, which is the entire contract duration. This constraint is costly for the natural gas sector and likely exaggerated. This is because base-load dispatch is extremely unlikely in a system rich with wind and hydro capacity and the gas commitment disregards unproven reserves despite the long horizon of the contract. In addition, the contractual requirement applies to all candidate projects served by this supplier, even though it is unlikely that all of them will win the auction. (It would be possible instead to have thermal plants compete for a given gas volume.) In addition, the electricity sector's new capacity auctions often impose constraints on operational parameters for candidate thermal plants, such as a maximum value for the declared inflexibility (linked to take-or-pay clauses), a maximum value for the plant's unit variable cost (which mostly depends on its fuel price), and a limited set of acceptable references for fuel price indexes.

Treating the gas industry as submissive to the power sector imposes a major burden on it that is not compatible with the benefits that the natural gas industry confers to electricity system planning. This challenge will become even more relevant as the development of the abundant Pre-Salt gas fields unfolds.

For the region to exploit its gas resources in an optimal way, more coherent long-term planning and institutional coordination will be necessary.

Chile: Risks and Challenges in Natural Gas Supply

Chile is one of the most energy-dependent countries in Latin America and also an interesting case study of successful and failed attempts to integrate electricity and gas in Chile. Much hope is being placed nowadays (somewhat naively) on a future low-priced and abundant supply of unconventional gas from the United States.

There are two major interconnected power systems, the northern one (SING) and the central system (SIC); together, they provide nearly 99.1% of the country's installed generation capacity. The SING system is almost 99.6% thermal and 0.4% hydraulic, while the SIC has a mix of 41.7% hydroelectric, 56.2% thermoelectric, and 2.1% of wind generation capacity. The SIC, in the central part of Chile, feeds more than 92% of the country's population and has an installed gross capacity of 14,466 MW as of December 2013 and a maximum demand of 7,283 MW. The SING, in the northern region, has an installed gross capacity of 3,995 MW with a maximum demand of 2,243 MW.

As mentioned, Chile is very energy-dependent, with 73% of its primary energy mix coming from abroad. This is because the country has limited coal, oil, and gas resources. Its hydro reserves in the Andes Mountains provide, along with biomass, the most significant local resources, and much hope has also been placed on future solar energy development in the Atacama Desert, with its abundant solar insolation (6.9 kWh/m^2/day). Given these facts, the main power system grew initially through the development of most of the low-cost hydro resources in the central part of the country. Important run-of-river and reservoir plants were developed, with significant reserves remaining thousands of kilometers south of the main load. This expansion was coupled with thermoelectric plants based on imported coal, chosen as the most economic backup supply option for dry years and since the local coal resources were of poor heat quality and high in pollutants relative to imported coal.

The use of natural gas in the country is a recent development with a complex history, which has brought important benefits but also caused much harm. It all started with Argentinean gas arising as an attractive, abundant, low-cost alternative. The competitive private power industry in Chile saw in this resource a great potential to reduce costs and secure supply. Governments gave their support, and an energy integration protocol was signed in 1995 between the two countries. Under that protocol, both governments agreed to establish the necessary regulations to allow freedom of trade and the export, import, and transportation of natural gas. Private investors were strongly behind the process and invested heavily in several pipelines that crossed the Andes and defined a path for energy development that would rely heavily on efficient combined-cycle generation plant technologies. Imports of natural gas for power generation started in 1997 when GasoductoGasAndes, a privately developed transportation pipeline, was inaugurated, bringing gas from the Neuquén Basin in Argentina to the central zone of Chile. Industrial and residential consumers also benefited from this interconnection.

Given the low-cost gas provided by Argentina (US$2 per million Btu) and its assumed abundant supply, traditional hydro and coal-fired technologies became uncompetitive, and plans to expand them were halted. The protocol worked very well at first, and Chile fully relied on Argentina to provide the necessary energy required to sustain its economic growth. Gas exports grew steadily, transported through several pipelines. The thermoelectric generation and petrochemical industries became the main consumers of natural gas. The arrival of this economic fuel and the efficient generation technologies it enabled led to a significant reduction in electricity prices in the two main interconnected systems. Natural gas became a key part of the Chilean energy mix, contributing 27% of total generation production.

Meanwhile, a severe macroeconomic crisis was growing within Argentina, coupled with the global crisis that took place in the early 2000s. Argentina started facing economic problems, which together with some questionable government decisions led to an energy deficit. Natural gas prices were reduced to a third of their previous levels (due to a severe devaluation of the Argentinean peso), and this led to an escalating demand that was not necessarily backed by investment in the exploration of new gas fields or in new pipelines. Gas rationing was on the horizon but was considered politically unfeasible. The Argentinean government decided to favor national supply and did not comply with its international agreements with Chile and other neighboring countries, such as Uruguay. Cuts to the gas transfers to Chile started taking place: not only interruptible but also firm contracted natural gas supply was curtailed in Chile, negatively affecting the Chilean power generation and industrial sectors. The situation worsened in 2005 with the decision of the Argentinean authorities to prioritize their domestic market supply in all cases, thus discriminating against Chilean consumers.

> Another important element is that the region has a long history of major hydroelectrical development, coupled with the use of coal in thermal generation.

Unfortunately, the Chilean government and the electric companies failed to anticipate the emerging critical conditions and were caught unprepared. The National Energy Commission's indicative plan of April 2004 (formulated by the regulator every six months), for example, foresaw the building of seven combined-cycle natural gas plants in the following ten years, all fed by pipelines from Argentina. Major new hydro plants and interconnections with other systems were postponed until 2010 or later, as gas continued to be seen as the major driver of expansion in a market with demand growing by around 7% each year.

Bolivia holds significant natural gas resources and would have been a natural alternative natural gas supplier; indeed, it significantly increased its exports to Brazil and Argentina, helping the latter cope with its crisis. But given its long history of border disputes with Chile (Bolivia lost its access to the Pacific in a 19th-century war with Chile), Bolivia refused to provide its next-door neighbor with natural gas, leaving Chile with no regional alternatives for gas supply.

The government started looking into regulatory alternatives. Capacity payment regulations were modified to better take into account an unreliable gas supply. A gas "drought" concept was introduced, derating combined-cycle plants that did not have alternative fuel arrangements and therefore reducing their capacity payments. Another alternative that was considered but eventually dismissed was to limit by law the country's dependence on foreign fuels to a certain percentage of national consumption; the core idea was that imports from a particular country should not exceed a certain value.

With the crisis developing, the October 2004 indicative plan introduced radical changes to the government view of energy supply expansion. Only one combined-cycle plant based on Argentinean gas was considered for 2007. The government decided instead to rely on LNG as the alternative and defined projects to build the necessary installations to import it from abroad. Coal-fired generation and hydro resources in the southern part of Chile resurfaced as alternatives for future development.

A new period in the history of natural gas in Chile began with the completion of two private LNG terminals, GNL Quintero and GNL Mejillones, which supplied the SIC and the SING respectively with a more secure and reliable source of natural gas. Both initiatives were set in motion by the government, which requested two state subsidiaries to enter into negotiations with the private sector. In effect, President Lagos requested Enap, the state oil company, to begin taking action in that direction, and Enap was successful in obtaining the support of the largest Chilean generator (Endesa), the gas distribution company for the capital city of Santiago (Metrogas), and an LNG provider (British Gas). The GNL Quintero terminal began operations at the end of 2009. Quintero is a terminal for the reception, storage, and regasification of LNG, supplying Santiago and the central zone of the SIC. It has storage tanks with a total capacity of 174,000 m^3 and a regasification plant that can process 10 million m^3 of gas per day as a base amount and up to 15 million m^3 per day when necessary. The design of the plant permits regasification of up to 20 million m^3 per day. British Gas sold its 20% stake in the terminal in 2013 and is now the sole supplier of LNG. The terminal is currently owned by Endesa Chile (20%), Metrogas (20%), Enap (20%), and the partner companies Enagas and Oman Oil (40%).

A second initiative was started by President Bachelet, who requested that Codelco, the state copper company, partner with potential private agents in the northern system in order to construct a second LNG terminal. GDF Suez joined the initiative and now owns 63% of the project; Codelco holds the remaining 37%. GNL Mejillones has been in operation since early 2010 and consists of a floating receiving and regasification terminal built in northern Chile. It initially stored LNG in a floating unit, after which the fuel went through regasification and was transferred to land via pipeline. A land storage facility with a capacity of 175,000 m^3 of LNG replaced the floating one in early 2014. Chile has consumed LNG arriving from Algeria, Egypt, Equatorial Guinea, Qatar, Trinidad and Tobago, and Yemen.

In 2012, other companies announced their interest in developing potential LNG projects. Colbun and Gener in central Chile indicated they were considering floating terminals to feed their existing plants, and Octopus indicated its interest in building a floating plant and a new combined-cycle generator in southern Chile. These are preliminary projects, and as yet no relevant developments have taken place to ensure they will be effectively developed.

Gas Regulation

Aside from the Magallanes zone in Patagonia, where state-owned Enap took the lead, the natural gas business in Chile has mostly been developed through private initiatives. The sector is thus essentially nonregulated in terms of structure, contracting, and pricing. Gas was seen by the private sector as an attractive new business when Argentinean natural gas

On a brighter note, the very needs of the region are already driving the search for a solution, and there are several opportunities for gains if one knows where to look.

was introduced in the early 1990s. The Chilean government at the time studied different regulatory alternatives for gas transportation and distribution and decided to follow a market approach, with minimal government intervention.

The Chilean constitution gives the state the absolute ownership of hydrocarbon deposits. It also states that exploration and exploitation can be carried out 1) by the state or its companies directly, 2) by means of administrative concessions, or 3) by special contracts of operation with private investors. According to Bahamondez, writing in *Gas Regulation 2014,* these contracts do not affect state ownership of the fields and they are not concessions; they grant certain relevant rights and benefits for both public and private parties. Nevertheless, gas transportation and distribution are not regulated, nor do they involve fixed tariffs. Gas transportation is subject to open-access rules, where the company owning the pipes must make public offers of available transportation capacity to third parties. These offers must be made with equal economic, commercial, and technical conditions for all participants. Prices are freely determined by the offering company, normally through the negotiation of long-term contracts.

Recent Power Infrastructure Developments

Chile is facing new challenges in its power infrastructure development as large hydropower and coal-fired power plants are running into strong social opposition due to environmental issues. Current examples include projects such as Barrancones (coal-fired; 540 MW), Punta Alcalde (coal-fired; 740 MW), Castilla (coal-fired; 2,100 MW), HidroAysén (hydro generation; 2,750 MW), Cuervo (hydro generation; 640 MW), and even existing plants such as Bocamina II (coal-fired; 350 MW). These difficulties are compounded by the increasingly litigious nature of the project approval process, which has resulted in delays for some projects and the outright cancellation of others. This has given rise to uncertainty regarding the long-term development of the generation supply. At the same time, generation from nonconventional renewable energy (NCRE), defined as all renewable energy except hydro plants with capacities greater than 20 MW, is being favored. A recent law defines having 20% of total generation supplied by NCRE by 2025 as a policy objective. There is a great deal of conflict over how the remaining 80% of generation should be supplied; natural gas is favored by environmentalists as a lower-emitting alternative that also has the dispatchability attributes so necessary as a complement to intermittent renewable resources.

On the other hand, there are dual-fuel combined-cycle plants that are burning diesel because they have no natural gas contracts. The recently elected government is examining this issue. A first challenge is how to contract and bring LNG to supply gas to those plants currently being used suboptimally. A second challenge is to define whether a gas-only path should be defined for system expansion, leaving out coal-fired generation entirely. The government is first assessing how to open the existing LNG terminals to third parties, arguing that the status of the terminals as essential facilities justifies the intervention. It is facing opposition by the private owners of Quintero, who took the initial risk of building it in 2008–2009, making considerable investments. Quintero only foresees business with potential third parties if there is gas and capacity available. The northern Mejillones terminal is offering regasification and storage services to any potential interested party under the open-access rules. The third party would need to find its own LNG supply—a solution that has not yet produced any agreement.

The issue of whether to leave coal out of the expansion plan is a difficult one, as the price at which LNG reaches Chile makes gas a more expensive fuel alternative. Energy generated by LNG combined-cycle units is around 20% more expensive than energy from coal-fired generation, as shown in Table 1. Even with prices of gas in the United

table 1. Levelized cost of energy for coal-fired (circulating fluidized-bed boilers) and natural gas–fired (LNG combined-cycle) thermoelectric plants.

	Coal	LNG—Combined Cycle
Unitary investment	US$2,400–2,800/kW	US$1,000–1,200/kW
Capacity factor	85–90%	50–80%
Fuel prices	US$100–130/t	US$11–13/MMBtu
Variable cost	US$37–47.5/MWh	US$74.5–88.1/MWh
Debt-equity rate	70/30%	70/30%
WACC rate (real)	8.43%	8.43%
Levelized cost	US$77.2–97.3/MWh	US$89.5–112/MWh

States at around US$4–6/million Btu, the value at the end of the liquefaction-transport-regasification chain would be between US$9 and US$14 (see Figure 5). Shale gas from the United States is seen in Chile as a promising alternative for gas supply in the long term, but Henry Hub gas price forecasts generally point to a gradual increase in the price level. The considerable uncertainty regarding gas prices adds to the risk that would accompany any eventual decision in this direction. In contrast, coal price forecasts tend to be more stable, given the abundant coal resources distributed worldwide.

Besides the cost competiveness of natural gas combined-cycle plants compared with coal-fired plants and hydro projects, there are other important issues that affect the integration of the gas and electricity markets. It is well established that electricity markets require capital-intensive investments with long payback periods, sometimes extending to more than 20 years. Long-term PPAs are required to reduce the spot market volatility. This results in a stable cash flow that would allow financing structures such as project finance, being the most common nonrecourse loans. This financing structure is becoming increasingly common, especially in projects developed by newcomers to the Chilean market, where the assets and cash flows produced are used to secure the loan. Under this financing structure, the electric energy taker needs to subscribe to a forward contract that usually matches the duration of the financing loan.

This structure is common regardless of whether the plant's source of energy is coal, natural gas, or hydro. There is a substantial difference between coal and natural gas, however. Coal can be supplied from a great number of providers around the world and stored at the power plant facility at relatively low cost, discounted for financial costs. Coal supply contracts can therefore have a shorter duration, can be renegotiated several times over the lifetime of a power plant, and can incorporate flexibility due to the coal storage available at the power plant.

The integration of natural gas with electricity generation marries two capital-intensive industries that often use the same type of financing structure; both industries therefore require long-term gas supply contracts to finance both the liquefaction and regasification infrastructure. And given the geographical location of Chile, all LNG shipments are committed from the supplier with little or no alternative market for the gas. To summarize, efficient LNG supply to Chile is based on long-term supply contracts with important take-or-pay clauses. The possibility of acquiring LNG in the short-term spot market exists but the resource must be purchased at a high price.

Electricity supply based on LNG requires strong linkages between the two industries that include a number of participants: the electricity energy taker; the power plant; the land transporter of the gas; the providers of regasification and gas storage; the LNG maritime transporter; the liquefaction owner; and the producer of the gas. This structure has become very relevant for supply based on shale gas from the United States, with whom Chile has a free-trade agreement that would facilitate the potential importation of gas.

In particular, to develop the required infrastructure there must be a close match with regard to several aspects of the supply chain. These include quantity, take-or-pay provisions, contract duration, and creditworthiness, among other elements. This situation has become a major barrier for new projects because the only way to make such a supply chain possible is with a long-term purchase agreement that meets all of the required conditions. It must also be timely

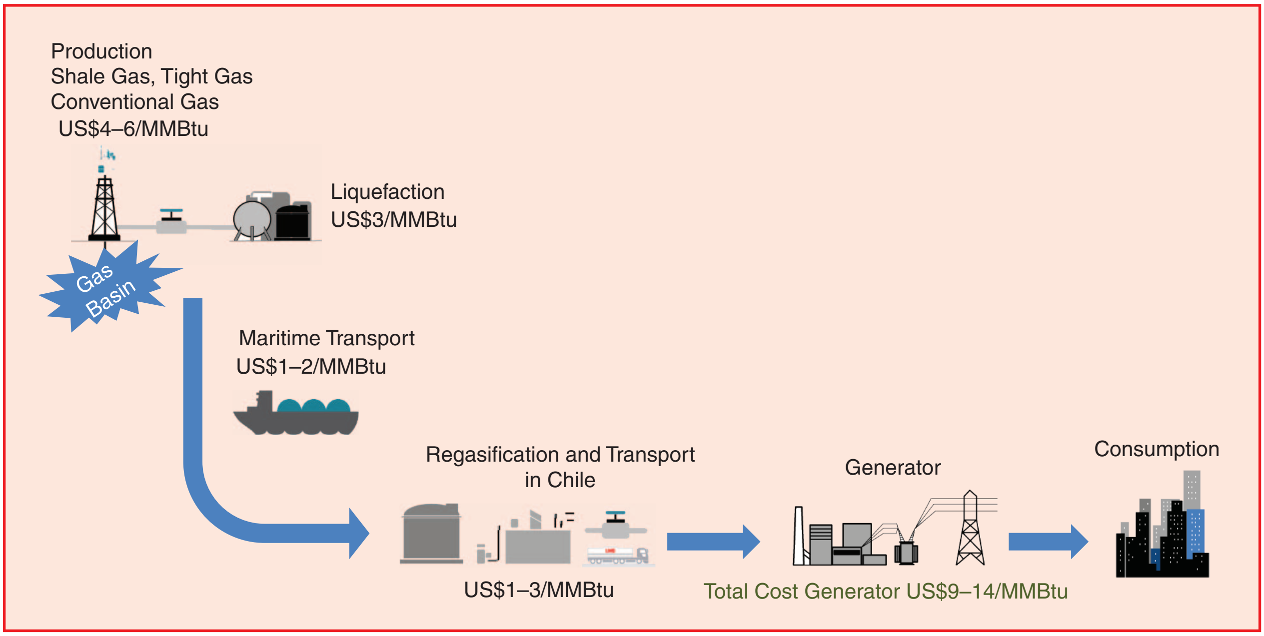

figure 5. Supply chain for natural gas to Chile.

so as to allow for the infrastructure construction and for the shale gas liquefaction terminals to be available. The industry structure described here is potentially a market changer. The market for electricity supply contracts to regulated consumers in Chile is currently under review by the government because these consumers have a market share of approximately 50% and could be used to support potential LNG development through long-term contracts and adequate indexation formulas. Big consumers such as large copper mines have even subscribed to supply contracts that are similar to tolling agreements and that allow for new combined-cycle plants in Chile.

A final challenge that arises in Chile, similar to the one described for Brazil, is making take-or-pay LNG contracts comply with a hydrothermal system in which the hydrology is variable and unpredictable. This makes it almost impossible to contract defined LNG volumes well in advance—usually a requirement to access competitive gas prices. Even existing take-or-pay contracts are difficult to manage, and the Chilean system operators have had to consider zero-priced gas at times of "spilling" gas conditions. The government has considered changing its regulation to consider take-or-pay contracts as being similar to hydro reservoirs in order to minimize dispatch risks. Take-or-pay supplies, although they are essentially rigid contract structures, can incorporate flexibility so as to increase or reduce the amounts of LNG committed. This flexibility comes with a cost, however, and normally requires a long lead time for decision making, a lead time that is sometimes too long for hydrothermal systems.

Conclusions

Even though the histories and current difficulties of the natural gas sectors in Brazil and Chile are very different, the two countries' experiences illustrate some of the main obstacles to promoting greater energy integration within the region. Opportunities for deeper regional integration are plentiful, although exploiting them will require surmounting multiple institutional barriers, both national and international.

Some common elements in the Brazilian and Chilean stories are the importance of the power sector as a driver for the development of the natural gas sector and the role of LNG as a potential "savior" in the face of the countries' natural gas supply deficits. If, on the one hand, integration with the global LNG network has been extremely positive for both countries, on the other hand, it is not certain that the best strategy is for Latin America to remain a net importer of LNG going forward. Both Brazil and Argentina have substantial gas reserves, but the insufficiency of the actual domestic natural gas supply was only identified when it was too late to take any measures to increase production, which led to LNG being sought out as an emergency measure. For the region to exploit its gas resources in an optimal way, more coherent long-term planning and institutional coordination will be necessary. In particular, the submissive stance that the natural gas sector has assumed in Brazil has been unhealthy for the country as a whole, preventing some win-win solutions from being adopted immediately.

On a brighter note, the very needs of the region are already driving the search for a solution, and there are several opportunities for gains if one knows where to look. In particular, the seasonality of Latin America's natural gas demand tends not to follow international demand patterns, due both to the large participation of hydroelectricity (and the high potential for other renewable sources) in the region's electricity mix and due to its position in the southern hemisphere. As a consequence, fully integrating the region into the worldwide LNG network could bring substantial gains.

Acknowledgments

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For Further Reading

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