Overview

Brazil is a significant energy producer. For many years, Brazil’s government has worked to increase domestic oil production, and discoveries of large, offshore, pre-salt oil deposits have transformed Brazil into a top-10 global liquid fuels producer.

Figure 1. Map of Brazil

Source: U.S. Central Intelligence Agency, World Factbook

Petroleum and other liquids

Sector Organization
State-controlled Petróleo Brasileiro S.A. (Petrobras) is the dominant participant in Brazil's upstream, midstream, and downstream oil sector activities. The company held a monopoly on oil-related activities
in Brazil until 1997, when the government opened the sector to competition. In 2003, Royal Dutch Shell was the first private company to begin commercial oil development when it started production in the Bijupirá and Salema fields in the Campos Basin. Later, other international oil companies (IOCs) began operating in Brazil, including:

- Chevron
- Repsol
- BP
- Anadarko
- El Paso
- Galp Energia
- Statoil
- Sinochem
- BG Group
- Sinopec
- ONGCTNK-BP

In addition to the IOCs, domestic companies began competing in the oil sector: OGX started to produce oil in the Campos Basin in 2011.

Much like in the refining sector, Petrobras holds most of Brazil’s logistics infrastructure. The company’s main clients, in addition to the Petrobras System, are distribution and petrochemical companies. Petrobras’s wholly owned subsidiary, Transpetro, operates Petrobras’s oil and natural gas production, logistics, and refining and distribution areas by transporting and storing oil, natural gas, derivatives, and biofuels. Transpetro transports imported and exported cargo of oil and other products.

The investigation of Petrobras (Operation Car Wash) in Brazil and the United States for bribery and money laundering started in 2014 and did not end until early 2021. The scope of the scandal extended to allegations of government corruption in several countries and a kickback scheme involving several international companies. The investigation resulted in a number of arrests and Petrobras losing more than $8 billion. According to Brazil’s government, during the seven years of investigation, 278 people were convicted of bribery and money laundering, including some of Brazil’s most prominent politicians and business owners.¹

Petrobras is one of the most heavily indebted national oil companies in the world, in large part due to lost revenue and fines from Operation Car Wash. In 2020, Petrobras reduced its debt from $126 billion at its peak in 2015² to $76 billion in 2020³, and it plans to reduce the debt to $60 billion by 2022.⁴ Petrobras’s strategy to reduce its debt relies on a strong restructuring plan through a divestment program. At the time of writing, Petrobras’s plan includes divesting its stake primarily in its onshore and shallow water oil fields, in approximately half of its domestic refining capacity, and in other segments of transportation and distribution. BR Distribuidora, the fuel distributor subsidiary of Petrobras, which was sold in 2019, is the first case of privatization of a state-owned company through capital markets in Brazil.

The principal government agency charged with regulating and monitoring the oil sector is the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP). ANP is responsible for issuing exploration and production licenses and ensuring compliance with regulations.

In 2018, the ANP approved changes to rules that set the minimum percentages of the locally sourced goods and services required in exploration and production contracts (known as local content). The local content rules apply to contracts, including the first-ever production-sharing agreements, for older bid rounds and projects through 2030. These changes could significantly affect Brazil’s growth in oil
production in the future, and breakeven prices could fall significantly and lead to increased oil production. The new local content rules require 50% of good and services for onshore projects to come from local sources and 18% for offshore deepwater projects. The government also instituted less stringent fines for companies that cannot fulfill these local content requirements. However, companies will no longer be able to apply for a waiver of these fines.5

Brazil’s previous local content rules were seen as a disincentive for investment because of the limited and uncompetitive local supply chain.6 Previously, oil and natural gas operators in Brazil were required to use up to 85% of equipment and services from domestic industry. This requirement was one of the highest local content requirements in the world, contributing to high breakeven prices.

**Exploration and Production**

More than 94% of Brazil’s oil reserves are located offshore, and 80% of all reserves are offshore near Rio de Janeiro. The next largest accumulation of reserves is located off the coast of Espírito Santo state, which contains about 10% of the country’s oil reserves. Reserves will likely rise as producers further explore pre-salt resources.

**Pre-Salt Oil**

Pre-salt oil refers to oil reserves that are exceptionally deep below the ocean and under thick layers of rock and salt. The large depth and pressure involved in pre-salt production present significant technical hurdles.

The first discoveries in Brazil’s pre-salt layer occurred during the 1980s. However, these discoveries were less significant because of the lack of technology at the time. Before 2005, exploration activity was mainly focused on post-salt (above the salt layer) discoveries. In 2005, Petrobras drilled exploratory wells near the Tupi field and discovered hydrocarbons below the salt layer. In 2007, a consortium of Petrobras, BG Group, and Petrogal drilled in the Tupi field and discovered an estimated 5 billion–8 billion barrels of oil equivalent (BOE) resources in a pre-salt zone at 18,000 feet below the ocean surface, under a thick layer of salt. For comparison, EIA defines ultra-deep drilling in the Gulf of Mexico as drilling at 5,000 feet or more.

Further exploration showed that hydrocarbon deposits in the pre-salt layer extended through the Santos, Campos, and Espírito Santo Basins. The Santos and Campos Basins, which hold the majority of the pre-salt reserves, contain approximately 13 billion barrels of Brazil’s proven oil combined, which accounts for over 94% of pre-salt reserves and 78% of the national oil reserves.7 According to a 2015 report by the National Institute of Oil and Gas at Rio de Janeiro-State University, they estimated pre-salt reserves were at 176 billion barrels of undiscovered, recoverable resources of oil and natural gas.8

In July 2017, output from pre-salt offshore wells surpassed combined volumes from all other fields for the first time.9 Pre-salt production reached a record level of 1.9 million barrels per day (b/d) in 2020, and it accounted for over 70% of total oil production in Brazil. Petrobras brought a number of floating production storage and offloading vessels (FPSOs) online between 2018 and 2020 in the pre-salt fields (Table 1).

**Table 1: Major pre-salt FPSOs online, 2018–2020**

<table>
<thead>
<tr>
<th>FPSO</th>
<th>Operator</th>
<th>Capacity (thousand barrels per day)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-74</td>
<td>Petrobras</td>
<td>150</td>
<td>Buzios field</td>
</tr>
<tr>
<td>P-75</td>
<td>Petrobras</td>
<td>150</td>
<td>Buzios field</td>
</tr>
</tbody>
</table>
Petrobras’ Strategic Plan 2021–2025 includes 13 additional FPSOs online through 2025, including the largest planned FPSO in Brazil—FPSO P-80 in the Buzios field, which has an expected capacity 225,000 b/d. The 13 FPSOs’ combined capacity is 2 million b/d, and these FPSOs will be located in the Sepia, Buzios, Mero, Marlim, Itapu, and Tupi (formerly known as Lula) offshore pre-salt fields.10

Petrobras and its partners (Royal Dutch Shell plc, France’s Total SA, China’s CNOOC, and National Petroleum Corp) are developing Brazil’s first-ever lease under a production-sharing system (PSA), which the government signed in 2013.11 The Libra Consortium plans to continue undertaking the exploratory phase of discovery evaluation in the Libra block area until March 2025.12 Under this consortium, the group has installed three FPSOs in the Mero field, the third-largest producing field in the pre-salt area.

**Regulatory Reforms**

Before the pre-salt discoveries, Brazil’s law allowed all oil companies to compete in auctions to win concessions and to operate exploration blocks. Brazil’s government passed legislation in 2010, creating a new regulatory framework for the pre-salt reserves that included four notable components. The first component was the legislation that created a new agency, Pré-Sal Petróleo SA (PPSA), to administer new pre-salt production and trading contracts in the oil and natural gas industry. The company is also responsible for the technical and financial assessment of any hydrocarbon project in the area. The Mines and Energy Ministry supervises PPSA. The second component allowed the government to capitalize Petrobras by granting the company 5 billion barrels of unlicensed pre-salt oil reserves in exchange for a larger ownership share. The other two components established a new development fund to manage government revenues from pre-salt oil and to lay out a new PSA system for pre-salt reserves. In contrast to the concession-based framework for non-pre-salt oil projects, where companies are largely uninhibited by the state in exploring and producing, Petrobras is the sole operator of each PSA and holds a minimum 30% stake in all pre-salt projects. However, the law included incentives for companies to participate with Petrobras in per-salt development, including a signing bonus of $6.6 billion.

In 2016, Brazil’s government passed an offshore oil bill that allows greater private and foreign investment in developing Brazil’s offshore oil blocks, modifying the 2010 law. The new provisions changed Petrobras from mandatory operator to preferred operator, allowing the company to choose which blocks to bid on in the pre-salt areas. Except for the Libra field, the government non-competitively granted all pre-salt areas that began development before 2016 to Petrobras.

**Refining**

Unless major refining capacity is added in Brazil, we expect oil product demand to continue to outpace the country’s domestic refining capacity. Petrobras operates 13 of Brazil’s 17 refineries, which together

---

### FPSOs in Brazil

<table>
<thead>
<tr>
<th>FPSO</th>
<th>Company</th>
<th>Capacity (B/D)</th>
<th>Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-76</td>
<td>Petrobras</td>
<td>150</td>
<td>Buzios field</td>
</tr>
<tr>
<td>P-77</td>
<td>Petrobras</td>
<td>150</td>
<td>Buzios field</td>
</tr>
<tr>
<td>P-68</td>
<td>Petrobras</td>
<td>150</td>
<td>Berbigão and Sururu fields</td>
</tr>
<tr>
<td>P-67</td>
<td>Petrobras</td>
<td>150</td>
<td>Tupi field</td>
</tr>
<tr>
<td>P-69</td>
<td>Petrobras</td>
<td>150</td>
<td>Tupi field</td>
</tr>
<tr>
<td>P-70</td>
<td>Petrobras</td>
<td>150</td>
<td>Atapu field</td>
</tr>
<tr>
<td>Campos de Campos dos Goytacazes</td>
<td>Petrobras</td>
<td>150</td>
<td>Tartaruga Verde field</td>
</tr>
</tbody>
</table>

**Total**: 1,350

---

Source: Table by the U.S. Energy Information Administration, based on data from Petrobras
account for 98% of the country’s crude oil distillation capacity (Table 2).\textsuperscript{13} Most of the refineries are located near demand centers on the country’s coast.

### Table 2: Major oil refineries in Brazil

<table>
<thead>
<tr>
<th>Refinery</th>
<th>Operator</th>
<th>Crude distillation capacity (thousand barrels per day)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Paulínia (REPLAN)</td>
<td>Petrobras</td>
<td>434</td>
<td>Paulínia, São Paulo</td>
</tr>
<tr>
<td>Mataripe (RLAM)</td>
<td>Petrobras</td>
<td>279</td>
<td>Mataripé, Bahia</td>
</tr>
<tr>
<td>São Jose dos Campos (REVAP)</td>
<td>Petrobras</td>
<td>252</td>
<td>São Paulo, São Jose dos Campos</td>
</tr>
<tr>
<td>Duque de Caxias (REDUC)</td>
<td>Petrobras</td>
<td>239</td>
<td>Rio de Janeiro state</td>
</tr>
<tr>
<td>Araucária (REPAR)</td>
<td>Petrobras</td>
<td>208</td>
<td>Araucária, Paraná</td>
</tr>
<tr>
<td>Canoas (REFAP)</td>
<td>Petrobras</td>
<td>201</td>
<td>Canoas in the Rio Grande do Sul state</td>
</tr>
<tr>
<td>Cubatão (RPBC)</td>
<td>Petrobras</td>
<td>170</td>
<td>Cubatão, São Paulo</td>
</tr>
<tr>
<td>Betim (REGAP)</td>
<td>Petrobras</td>
<td>157</td>
<td>Betim, Minas Gerais</td>
</tr>
<tr>
<td>Abreu e Lima (RNEST)</td>
<td>Petrobras</td>
<td>88</td>
<td>Ipojuca, Pernambuco</td>
</tr>
<tr>
<td>Capuava (RECAP)</td>
<td>Petrobras</td>
<td>57</td>
<td>Capuava, Mau, Sao Paulo</td>
</tr>
<tr>
<td>Manaus (REMAM)</td>
<td>Petrobras</td>
<td>46</td>
<td>Manaus, Amazonas</td>
</tr>
<tr>
<td>Potiguar Clara Camarão (RPCC)</td>
<td>Petrobras</td>
<td>38</td>
<td>Guamaré, Rio Grande do Norte</td>
</tr>
<tr>
<td>Fortaleza (LUBNOR)</td>
<td>Petrobras</td>
<td>8</td>
<td>Fortaleza, Ceara</td>
</tr>
</tbody>
</table>

**Total** | **2,177**

Source: Table by U.S. Energy Information Administration, based on data from Oil & Gas Journal, 2021 Worldwide Refining Survey

In November 2014, the Abreu e Lima, or RNEST, refinery began processing crude oil, marking the first greenfield refinery addition in Brazil in more than a decade.\textsuperscript{14} In early 2015, Petrobras officially canceled the 600,000 b/d Premium I and 300,000 b/d Premium II refineries because of the company’s critical financial situation.\textsuperscript{15} In 2019, Petrobras and China’s National Petroleum Corporation (CNPC), its partner, completed an economic feasibility study and concluded it was not economical to complete construction of the previously stalled 150,000 b/d Petrochemical Complex of the Rio de Janeiro Comperj project, located in Itaborai, Rio de Janeiro. Petrobras canceled plans for refinery construction, along with its associated projects in the Marlim cluster of fields (Marlim, Marlim Sul, and Marlim Leste) in the Campos Basin.

As part of its Strategic Plan 2021–2025 to reduce debt, Petrobras plans to sell eight refineries—RNEST, RLAM, REPAR, REFAP REGAP, REMAN, and LUBNOR—by 2022. This plan will reduce its domestically owned refining capacity from 2.1 million b/d to 1.1 million b/d.\textsuperscript{16} In March 2021 Brazil’s government approved the sale of RLAM. This sale is the first refinery to be divested. Petrobras put the divestment of the other seven refineries on hold during 2020 in response to the COVID-19 pandemic, but the process has since resumed.\textsuperscript{17}
Biofuels

Regulatory Reforms
To address the country’s reliance on oil imports and its surplus of sugarcane, the government implemented policies to encourage ethanol production and consumption beginning in the 1970s.

The Ministry of Mines and Energy (MME) implemented the most recent biofuel policy, the National Biofuels Policy (RenovaBio), in December 2019. MME designed the program to support Brazil’s goals from the 21st Conference of the Parties (COP21) of the United Nations Framework Convention on Climate Change (UNFCCC). Brazil voluntarily committed to reduce domestic emissions of greenhouse gases (GHG) by 37% by 2025 and by 43% by 2030, compared with its 2005 emissions. RenovaBio targets are based on three mechanisms:

- Annual carbon intensity reduction targets for a minimum period of 10 years starting in 2020
- Certification of biofuels based on how efficiently they reduce GHG emissions
- Decarbonization Credits (CBios) traded in Brazil’s Stock Exchange

By creating a market for CBios, the RenovaBio program formalizes compensation for the sector’s role in reducing GHG emissions in Brazil.

In Brazil, ethanol and gasoline are competing products in a market where flex-fuel vehicles account for 60% of the total domestic vehicle fleet. Hydrous ethanol (E100) is the substitute product that flex-fuel vehicle owners switch to when its price is at or lower than 70% of the gasoline price.

Brazil’s government raised the ethanol blend requirement in gasoline to 27% in February 2015, and it is considering a further increase to 27.5% as a way to reduce gasoline imports. Brazil’s ethanol industry has been struggling because of land and labor cost increases as well as government-imposed gasoline price controls, which have been undermining the competitiveness of ethanol as an oil substitute. In addition, sugarcane, the main feedstock in Brazil’s ethanol production, is highly sensitive to weather. Crop yields can swing considerably year to year, adding significant uncertainty and costs to ethanol.

Biodiesel production remains tightly regulated by the government. In January 2005, Brazil’s government formally introduced The National Program of Production and Use of Biodiesel (PNPB). The program established a minimum blending percentage of biodiesel into petroleum diesel. At first, the suggested blending percentage (2%) was optional from 2005 to 2007, but it became mandatory in January 2008.

The biodiesel blending requirement has increased since 2008 to 13% (March 2021). PNPB lowered the biodiesel blending requirement to 10% between June 16 and June 21, 2020, because ANP approved a brief temporary reduction in response to the COVID-19 pandemic and potential supply shortfalls. Blending requirements are scheduled to increase 1% per year until at least 2028, when the percentage will reach 20% (B20).

Imports and Tariffs
Historically, Brazil has imported ethanol because of droughts that affected sugarcane yields along with the difficulty of producing ethanol from sugarcane, which if not processed quickly tends to rot. The seasonality of sugarcane harvests leaves Brazil with an off-season from January to March. In Brazil, ethanol production is also highly sensitive to commodity prices. For example, because sugarcane is used for ethanol production, high sugar prices may entice producers to switch to sugar production instead of ethanol production. Finally, demand in northeast Brazil for imported ethanol has been high as a result of insufficient local production and the higher cost of transporting ethanol from southern Brazil.
In August 2017, Brazil’s foreign trade chamber, Câmara de Comércio Exterior (CAMEX), approved a 20% tax on ethanol imports to take effect once a 600 million liter-per-year quota (10,339 b/d) is exceeded. The import tax ended an agreement between the two largest ethanol producers in the world, Brazil and the United States, to keep global ethanol trade free of taxes as a way to boost the industry and the market.

Since September 2019, ethanol producers have been allowed to import 750 million liters per year (12,924 b/d). Any volume exceeding the quota was taxed at 20%. This quota expired in August 2020, and all ethanol imports once again became subject to the 20% tariff in December 2020.

Natural Gas

Sector Organization
Petrobras plays a dominant role in the entire natural gas supply chain. In addition to controlling most of the country’s natural gas reserves and being responsible for most domestic natural gas production, Petrobras also manages natural gas imports from Bolivia. Petrobras controls the national transmission network, and it has a stake in the majority of Brazil’s state-owned natural gas distribution companies. Petrobras owns and operates virtually all of Brazil’s pipeline infrastructure through its subsidiary company Transpetro. In the upstream and the midstream sector, Brazil’s Ministry of Mines and Energy (MME) sets policy, and the ANP is the regulatory authority. In the downstream sector, state agencies oversee regulation.

As part of its strategy to reduce debt, Petrobras is selling its pipeline assets. In April 2017, Petrobras sold a 90% stake in Nova Transportadora do Sudeste SA (NTS) to a consortium of buyers. In 2019, Petrobras sold a 90% stake in Transportadora Associada de Gas (TAG) to a group formed by ENGIE and the Canadian fund Caisse de Dépôt et Placement du Québec (CDPQ). In 2019, Petrobras reached an agreement with anti-trust regulator, Cade, to sell off a series of natural gas transportation and distribution assets, including the remaining 10% stakes in NTS and TAG and a 51% stake in Transportadora Brasileira Gasoduto Bolivia-Brasil (TBG). In 2020, Petrobras continued to divest its assets by selling its liquefied petroleum gas (LPG) distribution unit, Liquigas.21

In April 2021, President Bolsonaro signed the New Gas Law, a regulatory framework for the natural gas sector (Bill of Law No. 4476/20). Key changes included:

- Companies interested in building natural gas pipelines will need a simple authorization rather than the more complex concession contract
- Energy regulator ANP will have additional authority to foster competition and reduce market concentration
- Power companies can now distribute natural gas for industrial use. Previously, only Petrobras served industrial natural gas consumers22

The goals of these reforms are to end Petrobras’s monopoly in onshore markets, to increase foreign investment, and to improve market efficiency.

Production
Most of Brazil’s natural gas reserves (84%) are located offshore, and 73% of offshore reserves are concentrated off the coast of Rio de Janeiro. Of the country’s onshore natural gas reserves, 59% of the reserves are in Amazonas.23
Three basins drive natural gas production in Brazil: Santos, Campos, and Espirito Santo. Recent announcements about additional natural gas discoveries in Brazil’s offshore pre-salt layer have generated interest about new natural gas production. Along with the potential to significantly increase oil production in the country, the pre-salt areas are estimated to contain sizable natural gas reserves as well.24 Associated natural gas projects in the massive pre-salt oil fields will account for the bulk of production growth going forward. However, as a result of the lack of offtake infrastructure from offshore fields to the mainland, challenges remain. Significant volumes of natural gas are currently reinjected or flared because of these infrastructure constraints.

**Pipelines**

Brazil’s pipeline system is a network of pipes situated predominantly along the southeast and northeast areas of the country, from Rio Grande to Sul to Ceará. For years, these pipelines did not connect, which hindered the development of domestic production and consumption. In March 2010, the Southeast Northeast Integration Gas Pipeline (GASENE) linked the southeast and northeast markets for the first time. This 860-mile pipeline, which runs from Rio de Janeiro to Bahía, is the longest pipeline in Brazil.

The other major natural gas market in Brazil is in the Amazon region. In 2009, Petrobras completed construction of the Urucu pipeline, which links Urucu to Manaus, the capital of Amazonas state. This project will facilitate development of the Amazon’s considerable natural gas reserves.

In 2011, Petrobras brought Rota 1 online, its first pipeline that transports pre-salt natural gas from the Tupi and Mexilhão fields in Santos Basin to its Caraguatatuba natural gas treatment unit to the REVAP refinery in Sao Paulo state. Rota 2 came online in 2016, and it connects the Tupi field to a natural gas treatment plant in Rio de Janeiro. A third pipeline operated by Petrobras that transports pre-salt natural gas will likely come online in 2022 and will connect the Santos Basin pre-salt fields to the Comperj refinery complex.

In recent years, Brazil’s state-owned Petrobras has divested from various midstream assets such as TAG and NTS, which together account for two-thirds of the country’s natural gas pipelines. Petrobras’s actions provide an opening for more market participants and aim to achieve greater market efficiency and lower prices.

**Imports**

Brazil relies on natural gas imports from Bolivia, which are transported through two pipelines, to help meet domestic consumption. Brazil also imports small amounts of natural gas from Argentina (Table 3). Imports from Bolivia have been steadily decreasing since 2015 as maturing natural gas fields in Bolivia continue to decline and domestic natural gas consumption rises in Bolivia, decreasing supply available for export.25 Bolivia’s contract to supply a minimum of 87 million cubic feet per day (MMcf/d) of natural gas annually to Petrobras expired in December 2019. Petrobras signed an extension agreement in 2020, but only after cutting the original contracted minimum volume by 60% to 34 MMcf/d.26 As a result of the recent increase in natural gas production from the vast Vaca Muerta shale field, Argentina is looking to increase its natural gas exports to Brazil.

**Table 3. Natural Gas Import Pipelines**

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Length</th>
<th>Origin</th>
<th>Destination</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasbol</td>
<td>1,960 miles</td>
<td>Santa Cruz, Bolivia</td>
<td>Corumbá, Brazil, continuing to São Paulo, Brazil</td>
<td>1.1 billion cubic feet per day (Bcf/d)</td>
</tr>
<tr>
<td>Río San Miguel -San Matías</td>
<td>391 miles</td>
<td>San José de Chiquitos, Bolivia</td>
<td>San Matías, Brazil; connecting to the GasOcidente pipeline</td>
<td>98 million cubic feet per day (MMcf/d)</td>
</tr>
</tbody>
</table>
As Brazil’s natural gas market continues to grow and available supply of natural gas imports from Bolivia decline, liquefied natural gas (LNG) will likely play an increasingly important role in meeting future demand growth, especially to the northeast markets that are disconnected from supply by infrastructure constraints.

Brazil has four LNG regasification terminals on the Atlantic coast with a combined regasification capacity of 2.2 billion cubic feet per day (Bcf/d) (see Table 4). In 2020, Petrobras announced plans to lease the terminal in Bahia in an effort to divest midstream and downstream oil and natural gas assets. The Guanabara Bay terminal has been idle since 2018 as it undergoes construction to expand capacity.

### Table 4. LNG import terminals

<table>
<thead>
<tr>
<th>LNG terminal</th>
<th>Location</th>
<th>LNG provided for</th>
<th>Operator</th>
<th>Regasification capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pecém terminal</td>
<td>Fortaleza</td>
<td>Ceará and Fortaleza thermal power plant</td>
<td>Petrobras</td>
<td>247 MMcf/d</td>
</tr>
<tr>
<td>Bahia terminal</td>
<td>Bahía</td>
<td>Onshore delivery points in the city of Salvado</td>
<td>Petrobras</td>
<td>494 MMcf/d</td>
</tr>
<tr>
<td>Guanabara Bay</td>
<td>Rio de Janeiro</td>
<td>Thermal power plants in the region</td>
<td>Petrobras</td>
<td>706 MMcf/d</td>
</tr>
<tr>
<td>Sergipe terminal</td>
<td>Sergipe</td>
<td>Usina Termoelétrica (UTE) Porto de Sergipe I combined-cycle natural gas-fired power plant</td>
<td>Golar LNG Limited</td>
<td>742 MMcf/d</td>
</tr>
</tbody>
</table>

All of Brazil’s LNG facilities are floating regasification and storage units (FRSU). Total import/regasification capacity is set to grow with three new projects. The first privately owned terminal, the Sergipe unit, came online in early 2020. The Acu Port project is under construction and will likely come online by 2021. The third project involves a capacity expansion of the existing LNG terminal at Rio de Janeiro.

As Petrobras reduces its involvement in midstream and downstream markets, new projects from private sector firms are emerging. According to a study by federal energy planning company Empresa de Pesquisa Energética (EPE), at least 23 new LNG terminals are planned in Brazil. As of the time of this writing, 10 are in the licensing phase, and 11 are the subject of initial studies. The status of the other LNG terminal is unknown.

### Electricity

#### Sector Organization

Until the 1990s, the government controlled almost all of the electricity sector. Brazil initiated an electricity sector privatization process in 1996 that led to the establishment of Agência Nacional de...
Energia Elétrica (ANEEL). The government also established a national transmission grid operator, the Operador Nacional do Sistema Elétrico (ONS), and a wholesale power market, the Mercado Atacadista de Energia Elétrica. ONS operates the national transmission grid, which consists of two large grids (one in the north, one in the southeast) and numerous smaller systems in isolated regions. ONS connected the north and southeast grids in 1999, and the combined system covers more than 90% of Brazil’s electricity market.

Although the electricity sector was privatized in the early 2000s, the bulk of Brazil’s major generation assets remain under government control. Eletrobras, the largest utility in Brazil in which the government is the main shareholder, is the dominant player in the electricity market. The government also owns most of the electricity transmission network.

In 2004, Brazil’s government implemented a new model for the electricity sector. This hybrid approach to government involvement splits the sector into regulated and unregulated markets for different producers and consumers. This approach allows both public and private investment in new generation and distribution projects. In February 2021, President Bolsanaro submitted a plan to privatize Eletrobras, which retains a government share of the company at 45% (down from a 61%). The sale will not include Eletronuclear (a nuclear power company owned by Eletrobrás) or the Itaipu hydroelectric dam.

Transmission
Brazil has a countrywide interconnected grid of over 100,000 miles of high-voltage transmission lines. Most of Brazil’s generation capacity is located far from urban demand centers, which requires significant investment in transmission and distribution systems. Total investments in the power transmission sector by 2029 will likely reach $22 billion, or $15 billion in transmission lines and $7 billion in substations. By 2029, an additional 32,000 additional miles will expand the grid. Plans for more distributed generation will help reduce the need for additional transmission infrastructure in the future.

The 1,580-mile long Belo Monte-Rio de Janeiro transmission line in Brazil is the world’s longest 800-kilovolt (kV) ultra-high-voltage direct current (UHVDC) transmission line. The line, also known as the Belo Monte UHVDC Bipole II line, transmits electricity from the Belo Monte hydroelectric power plant in Para to Rio de Janeiro. Construction of the transmission line began in September 2017 and was completed in April 2019. The Madeira transmission line, completed in 2014, is one of the longest high-voltage, direct-current line (HVDC) in the world and spans 1,476 miles to link hydropower plants in the Amazon Basin to major load centers in the southeast.

Hydroelectric Power
Brazil is the second-largest producer of hydroelectric power by installed capacity in the world, behind only China. Brazil relies on hydropower to provide more than 66% of its electricity, and in 2019, hydropower met more than 75% of electricity demand. Natural gas- and diesel-fired plants are used only to meet peak demand or as backup baseload sources.

Most of Brazil’s hydroelectric plants are located in the country’s Amazon River Basin in the north, but Brazil’s demand centers are located mainly along the eastern coast, particularly in the southern portion. Brazil’s reliance on hydropower for most of the country’s electricity generation, combined with the distant and disparate locations of its demand centers, has presented electricity reliability challenges. Increased droughts in Brazil have led to concerns about hydroelectric power generation. Water reservoirs have experienced decreased water levels since 2013, made worse by the 2015–2016 El Niño event in the southeast region that caused the worst water shortage in 35 years. Reservoirs remained...
at below-normal levels through 2021, which increased the use of more expensive thermoelectric power and led to higher electricity prices in Brazil.\textsuperscript{42}

The world’s largest hydroelectric plant by installed generation capacity is the 14-GW Itaipu hydroelectric dam on the Paraná River, which Brazil operates with Paraguay. According to Itaipu Binacional, the facility generated a record high of 103 million megawatthours (MWh) of electricity in 2016, as a result of higher rainfall and improved operating efficiency. In 2020, the facility generated 76 MWh after one of the driest years on record.\textsuperscript{43} Although Brazil is considering plans to reduce hydropower in the electricity generation mix to minimize the risk of supply shortages as a result of dry weather, new hydro projects continue to move forward. Most notable among these projects is the Belo Monte plant in the Amazon Basin, which reached full operating generation capacity in 2019. This facility is the second-largest hydroelectric plant by capacity in Brazil after the Itaipu Dam and is the fourth-largest hydroelectric plant by capacity in the world.\textsuperscript{44} Several other projects planned to come online by the end of the decade, include the 400-megawatt (MW) Tabajara hydropower project in 2027, the 650-MW Bem Querer Hydropower Project in 2028, and a handful of other projects at 100 MW or more between 2026 and 2029.\textsuperscript{45}

**Other Renewables**

The Brazilian Energy Planning Agency’s (EPE) Ten Year Energy Expansion Plan (PDE) for 2020 to 2030 shows that the development of renewable sources will remain a high priority for the government. The PDE expects renewable energy, including hydro, biomass, ethanol, wind, and solar, to account for 48% of all energy supply in the country by 2030.\textsuperscript{46}

Brazil has two nuclear power plants: the 640-MW ANGRA 1 and the 1,350-MW ANGRA 2. State-owned Eletronuclear, a subsidiary of Eletrobrás, operates both plants. The ANGRA 1 nuclear power plant began commercial operations in December 1984, and the ANGRA 2 began commercial operations in December 2000. Construction of a third plant, the 1,405-MW Admiral Alvaro Alberto Nuclear Power Station (CNA), formerly ANGRA 3, started in 1984 but has not yet been completed. We expect nuclear energy’s generation share to grow when Angra 3 comes online, which is estimated for 2026.\textsuperscript{47}

Solar generation is the smallest portion of electricity generation in Brazil, but its portion is also the fastest growing. Financial incentives such as government subsidies make solar energy cheaper for investors and end users. In 2019, ANEEL proposed to remove these subsidies and to impose a grid access tax for consumers, but President Jair Bolsonaro has postponed any changes.\textsuperscript{48} According to the Brazilian Association for Solar Photovoltaic Energy’s (ABSOLAR) analysis, more than 4.9 gigawatts (GW) of installed power will be added in 2021. This increase will represent a growth of more than 68% over the country’s current installed capacity, currently at 7.5 GW.\textsuperscript{49} The Ministry of Mines and Energy (MME) announced in 2020 that it expects over 8 GW of solar capacity to be added by 2030.\textsuperscript{50}

**Notes**

- Data presented in the text are the most recent available as of June 2021.
- Data are EIA estimates unless otherwise noted.