MINISTÉRIO DE MINAS E ENERGIA
SECRETARIA DE PLANEJAMENTO E DESENVOLVIMENTO ENERGÉTICO

2031

TEN-YEAR ENERGY EXPANSION PLAN

epe
Empresa de Pesquisa Energética

Ministério de Minas e Energia

7. Natural Gas

In this chapter, the results of studies on the evolution of the natural gas' demand and supply balance and its infrastructure in the period from 2021 to 2031 are presented.

Initially, the discussion focuses on the existing and under construction infrastructures. Later, it presents the following natural gas' outlooks: prices, demand in Brazil (comprised of non-thermoelectric demand and thermoelectric) and supply in Brazil (comprised of domestic production and imported gas). Subsequently, this document describes the balance between natural gas' demand and supply from the integrated transmission pipeline network and its thermo-fluid-hydraulic simulation. Finally, the chapter presents investments' estimates necessary for projects to expand the Brazilian infrastructure of natural gas' flowing, processing, and transmission.

This study incorporates the ongoing evolution of Brazilian natural gas market through the New Gas Market Program - NGM (Programa Novo Mercado de Gás), in which EPE has played an important role. This program seeks to create an open, dynamic, and competitive natural gas market in Brazil, promoting conditions to reduce its price and, thereby, contributing to the country's economic development. In addition to increasing the volumes supplied and consumed in the Brazilian market, the NGM Program aims to encourage the entry of new players, both through new projects that can make natural gas available to the market, and through third-party access to existing facilities. In the third-party access case, the use of the installed capacities of these facilities is thus optimized through negotiations between the players, on an economic basis and in a non-discriminatory manner.

It is important to note that Law 14,134 (New Gas Law) of April 8th, 2021, was enacted, followed by Decree 10,712 of June 2nd, 2021, thus establishing the new legal framework for the Brazilian natural gas industry. This PDE's version already incorporates the ramifications of the new legal framework.

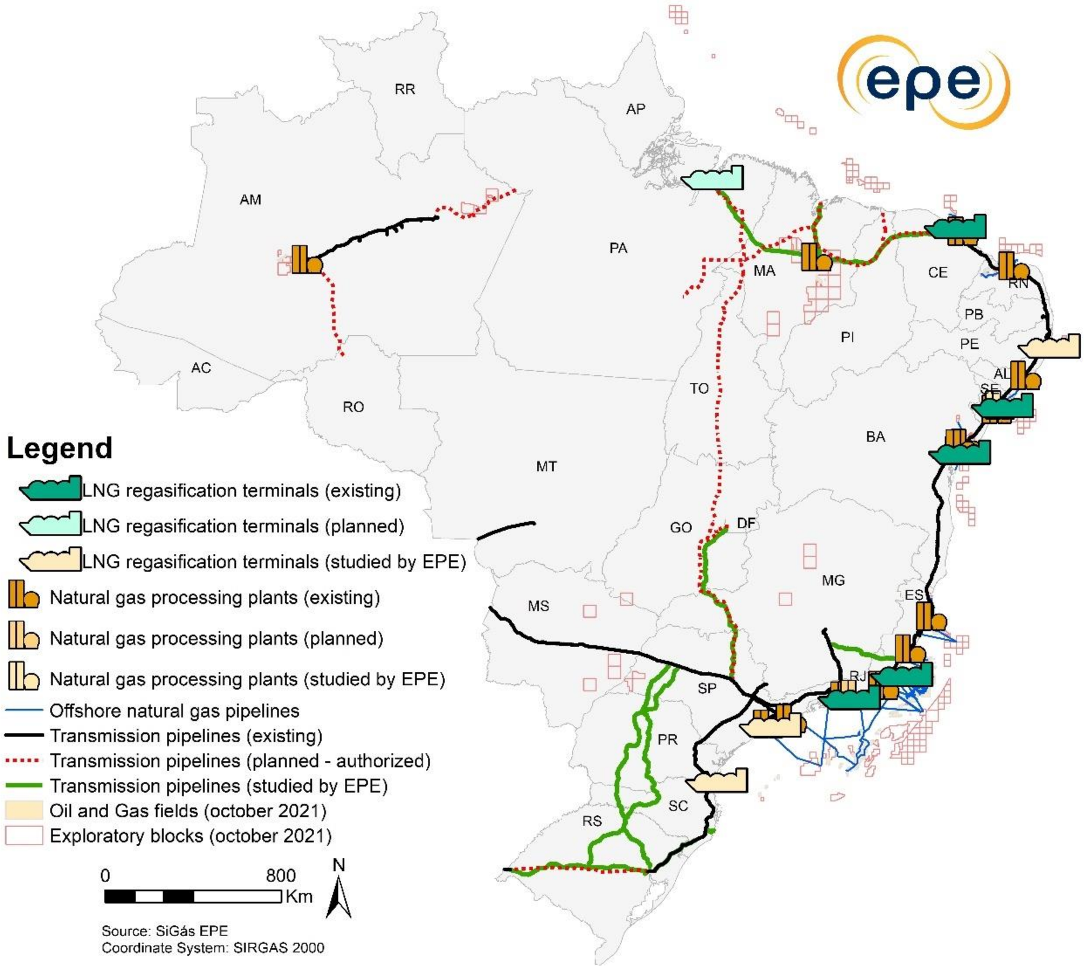
7.1 Infrastructure

The domestic transmission pipeline network, currently, has a 9,409 km total length, distributed across all Brazilian regions (MME, 2021). Besides the natural gas produced nationally and processed in 16 Processing Poles, this energy is also imported through 3 international transmission gas pipelines or in the form of liquefied natural gas (LNG) through 5 regasification terminals.

The Brazilian production natural gas pipeline network is currently composed of 265 gas pipelines, totaling around 4,564 km. The 146 transfer gas pipelines are equivalent to a total length of at least 1,765 km (MME, 2021). It is noteworthy that these natural gas pipelines are in regions with hydrocarbon production, such as the North (2 outflow gas pipelines), Northeast (235 outflow and transfer gas pipelines) and Southeast (174 gas pipelines of both types).

Figure 7 - 1 presents the existing and under construction natural gas processing and transmission infrastructure in Brazil, as well as the LNG regasification terminals in operation and planned.

Figure 7 - 1: Brazilian natural gas infrastructure: existing, planned and studied



Source: EPE.

Note: In previous PDE's versions, the natural gas treatment plants in Maranhão State were considered differently when compared to the other facilities in Brazil; however, from PDE 2030 on, they were considered equivalent to the other natural gas treatment plants, because it was considered that they could specify natural gas in accordance with ANP´s Resolution number 16/2008 after operational adjustments.

It is worth noting that the transmission network in the Northeast and Southeast, as well as the Bolívia-Brasil (GASBOL) and Uruguaiana-Porto Alegre gas pipelines (stretch 3), are interconnected and form part of the integrated network. The Lateral-Cuiabá, Uruguaiana-Porto Alegre (stretch 1) and Urucu-Coari-Manaus gas pipelines (as well as the Urucu Processing Hub) are considered isolated systems. Also worthy of note is the isolated Maranhão system, in the Parnaíba Basin, whose produced volume of natural gas is sent to a processing plant and used locally in the thermoelectric plants at the Parnaíba Complex, close to the production facilities.

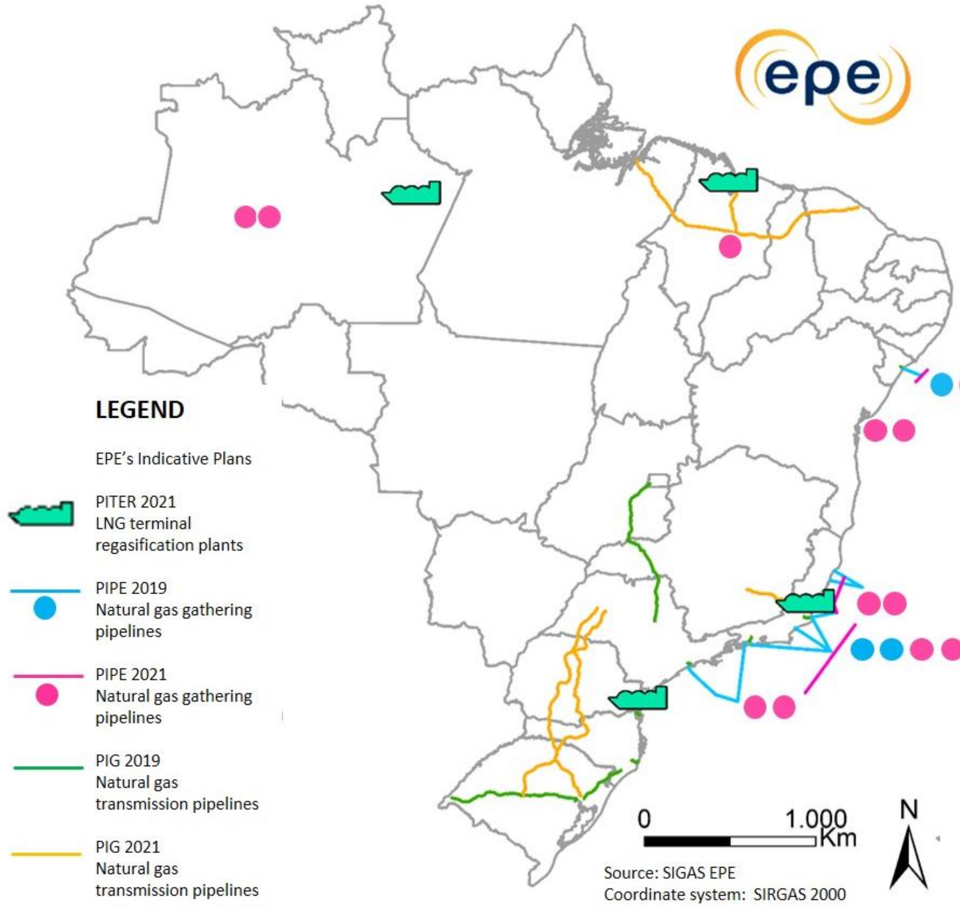
There are three projects under implementation: the natural gas processing plant at the Gaslub Complex (Itaboraí/RJ), the last stretch of Route 3 and the Itaboraí/RJ-Guapimirim/RJ transmission gas pipeline. These interconnected projects will have the potential to bring new volumes of natural gas to the network as of 2022 (PETROBRAS, 2021), in addition to reinforcing supply's security. The GASFOR II project is also under construction, which will reinforce the integrated network in the Northeast, solving possible specific logistical bottlenecks near Ceará State (TAG, 2021a).

In 2021, the implementation of the LNG terminal at Porto do Açu/RJ was completed, with a regasification capacity of 21 million m^3/day to supply Novo Tempo and GNA II Thermoelectric Power Plants (with maximum demand of approximately 6 million m^3/day for each plant). Also noteworthy is the LNG terminal project in Barcarena/PA, scheduled to start in 2022 and regasification capacity of 15 million m^3/day, to be connected to the Novo Tempo Barcarena Thermoelectric Power Plant (with a maximum demand of 3 million m^3/day) besides other industrial demands. Also, three additional LNG terminals are expected to be implemented in the ten-year timeframe: the Regasification Terminal of São Paulo/SP, the Terminal Gás Sul/SC, and the terminal of Suape/PE.

The excess capacity of current and future LNG terminals may become available to the integrated network, to the non-thermoelectric market, or to new thermoelectric power plants (UTEs) that win energy auctions, according to the entrepreneurs' strategy. Currently, there are not final investment decisions to connect these projects to the integrated network. Therefore, these projects were considered in this PDE's cycle as isolated systems to achieve the associated demands. However, for the existing LNG terminal in Barra dos Coqueiros/SE, the intention to connect the project to the national pipeline integrated network was recently announced (SEDETEC, 2021), and the Terminal Gás Sul/SC was authorized already considering its connection to the GASBOL through a new pipeline's construction (ANP, 2021a). Once the interconnection projects start to operate, these LNG terminals will contribute to raise natural gas availability to customers throughout Brazil via the integrated network.

The natural gas indicative projects studied by EPE in 2019 and 2021 represent the potential for infrastructure's expansion over the decade. Although these projects are only indicative, they portray investment opportunities over the period that can contemplate an industry's accelerated development scenario encouraged by the regulatory changes in 2021, notably Laws 14,134/2021 and Law 14,182/2021. **Figure 7 - 2** presents the indicative plans published by EPE in 2019 and 2021.

Figure 7 - 2: Indicative natural gas projects studied by EPE (PIG, PIPE and PITER plans)



Source: Prepared by EPE.
Note: Some alternatives of gas pipelines studied in the indicative plans PIG and PIPE have small extensions to be noticed in the map's scale, having been represented, in these cases, as points instead of lines. In this sense, it is suggested to read the complete publication for more detailed information.

7.2 Prices

After the price lows recorded in 2020 caused by the impacts of the pandemic, energy commodities rose sharply due to the resumption of economic activity, mainly in China and the USA, from extreme weather conditions in winter and summer in the northern hemisphere in 2021, to the advance in vaccination campaigns and the reversal of the impacts of the Covid-19 pandemic.

Several factors drive the natural gas' global demand, such as the replacement of storage levels in Europe and Asia and the increase in consumption for electricity generation in several countries. Pressures on demand have contributed to the maintenance of international reference prices at record levels, favoring LNG exports. Combining aspects of supply, demand and storage, the fundamentals of world natural gas markets indicate that prices will remain at high levels in the short term. New liquefaction projects are expected to start operating worldwide from 2024, balancing the international market and potentially lowering natural gas prices.

With the recovery of oil prices, as observed in the Brent and WTI[1] benchmarks, there was also an increase in prices for natural gas traded indexed to Brent. In fact, oil prices continued, in 2021, the recovery process that had been taking place since 2020, causing LNG prices to reach all-time highs in October 2021 (EPE, 2021a).

Thus, an increase was observed in the natural gas' prices traded both by indexation to Henry Hub and oil baskets.

With the modernization of the natural gas markets after the NGM Program and the Commitment Term signed between Cade and Petrobras, besides the various new players that recently started their operations in Brazilian gas sector and the negotiations for third-party access to the flow, processing and LNG regasification (MME, 2020), the commercialization of natural gas in Brazil begins to gradually migrate to contracts with greater liquidity and competition between different sources of supply, such as LNG, natural gas imported from Bolivia and natural gas produced domestically in different exploratory environments. Public calls made by local distribution companies (CDLs) have started a price discovery process like the process observed in countries that have consolidated hubs, and at least 9 new carriers have already entered the integrated network by contracts' subscription on the Capacity Supplying Platform - POC (TAG, 2021b). After the launch of the NGM Program in mid-2019, a 100% increase was observed in the number of players authorized by National Agency of Petroleum, Natural Gas and Biofuels (ANP) as traders, 300% in the number of shippers, and 500% in the number of importers (ANP, 2021b).

Based on price variations and new market dynamics, as well as their influence on the various sources of natural gas supply and on the respective production costs' estimates and margins, EPE estimated the domestic natural gas prices' trajectory in the timeframe from 2021 to 2031. In particular, EPE identified the most likely range of domestic and international prices, considering several possible sources of supply, as well as their commercialization in hubs and delivery to final consumers in different sectors.

The final average natural gas' prices for industrial consumers in different sectors were calculated from the prices' estimates of the molecules of national natural gas, imported via GASBOL and imported via LNG terminals, added to the transmission tariffs, the distribution margins and the main taxes. More specifically, three final consumer price paths were estimated:

i. upward trend, considering the continuity of the gas-oil competition, indexed to Brent;

ii. reference trajectory, considering hub trading and gas-gas competition; and

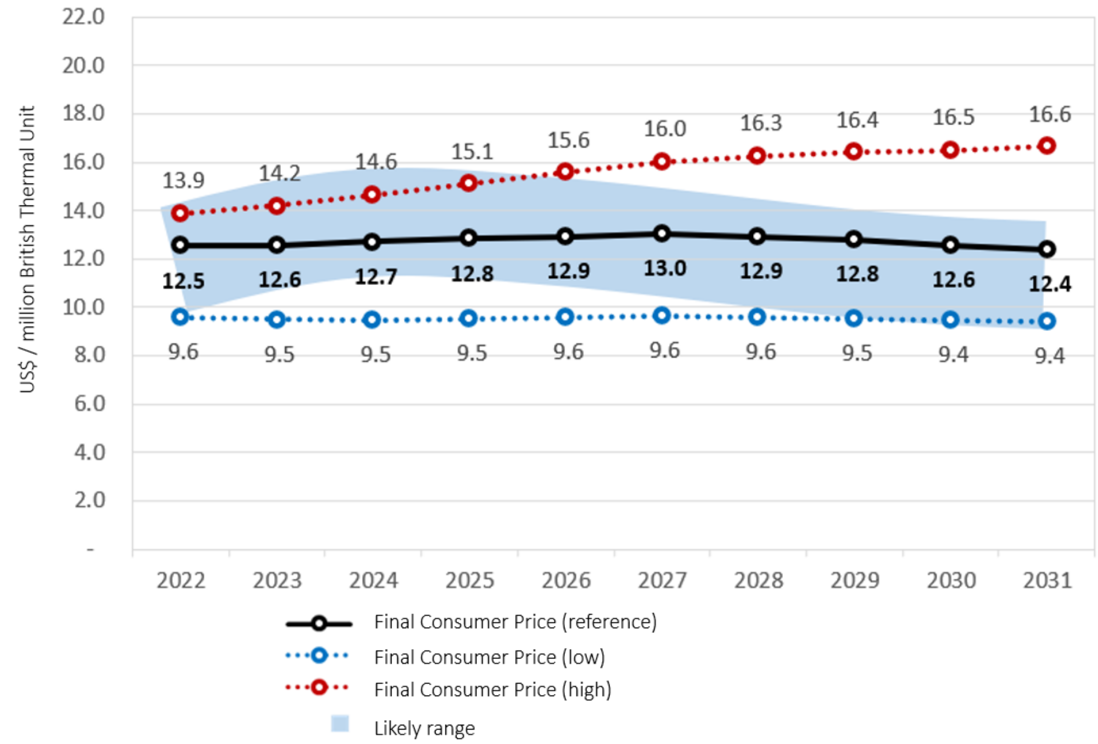
iii. lowering trend, considering trading in hubs, gas-gas competition and greater efficiency in transmission and distribution.

The three estimated trajectories are presented in Chart 7 - 1, as well as a likely price range that seeks to represent possible variations between the CDLs[2].

[1] WTI: West Texas Intermediate. Crude oil produced in Texas and southern Oklahoma that serves as a benchmark or "marker" for pricing other oil streams. Traded on the spot market in Cushing, Oklahoma, United States. (EIA, 2022)

[2] There is a tendency, motivated by the increase in the natural gas' price in the international market to renegotiate the contracts between Petrobras and the CDLs with an adjustment of up to 50%, possibly changing the price dynamics in the coming years.

Chart 7 - 1: Average price forecasts for industrial consumers with a consumption size of 20,000 m³/day, including transmission, distribution margin, ICMS and PIS/COFINS



Source: Prepared by EPE.
Note: ICMS - Tax on Operations related to the Circulation of Goods and on Provision of Interstate and Intermunicipal Transport and Communication Services; PIS - Social Integration Program; COFINS - Contribution to Social Security Financing.

It is noteworthy that they are average trajectories. In this way, probable range values lower than the downward trajectory would be possible depending on the type of consumer or contract, as well as in the case of consumers disconnected from the network and/or subject to specific tariffs for the use of the distribution system (TUSD-E), according to the applicable state regulation.

The players' diversity increase, and the greater liquidity brought by the NGM Program might contribute to an efficient transition from the previous gas-oil indexation to a gas-gas pricing logic for the Brazilian natural gas market. Although the LNG prices might be high in some months, especially during the northern hemisphere winter, it is expected the annual average's normalization over the years due to the entry into operation of new liquefaction terminals, regulating global flows.

This transition will bring benefits to Brazilian gas sector through access to natural gas' volumes at competitive prices, facilitating demand growth, and at the same time allowing prices to recover to the point of enabling domestic production. The Henry Hub benchmark will have greater influence on domestic prices in the short term, given the possibility of importing LNG from the US by more players. Furthermore, there is a possibility of existence of new natural gas contracts' models which will consider Henry Hub instead of Brent.

Over the next decade, the hubs' formation will promote the signing of standardized contracts, negotiated based on a domestic index. This index will be built over time with the gradual increase in the number of customers participating in the market.

7.3 Demand

The Brazilian natural gas' demand is divided into four main categories:

i. industrial, household, commercial and transport (VNG) sectors;

ii. refineries and nitrogen fertilizer plants (FAFENs);

iii. system use gas (consumed in compression stations and heaters in transmission gas pipelines); and

iv. thermoelectric plants (UTEs).

7.3.1 NON-THERMOELECTRIC DEMAND

The demand for natural gas for the industrial, household, commercial and transport sectors was consulted with the CDLs through the INFOGÁS system (EPE, 2021b), which also included surveys with large consumers. Of the 24 distributors contacted, which today carry out natural gas flow in their respective concession areas, 15 distributors sent data for this analysis, and the data received in previous cycles were updated for the rest. In addition, 1 large consumer sent data, which was made compatible with other distributors' data.

Consolidated demand data were guided by expectations of Brazilian gross domestic product (GDP) growth for the main industrial sectors. In the case of CNG, the data received were also aligned with the demand estimates calculated using EPE's internal models for the transport sector.

The natural gas demand for refineries and FAFENs was estimated considering their maximum consumption, the hibernation of units, the decrease and resumption of consumption by them, and the entry of new units in the study timeframe. The estimates were built based on meetings with industry players and owners of these units, considering their technical and economic assumptions.

Once the leasing of FAFENs in Bahia and Sergipe States were finalized, their demands were considered at the maximum capacities' levels in this PDE's cycle, as well as the refineries at their maximum capacities. As in PDE 2030, the Araucária Nitrogenados S.A. or FAFEN-PR, with consumption of 0.54 million m^3/day, was considered dormant, but this unit could resume operations in 2024 if its sale process becomes concluded. The start-up of the Três Lagoas/MS Nitrogen Fertilizer Unit (UFN) in 2027 was also considered, with consumption of 2.3 million m^3/day. The natural gas' consumption at the Gaslub Itaboraí Complex until 2031 was not considered in this analysis, given the uncertainties in its characteristics.

The estimation of the volumes of gas used by the system considered the maintenance of current levels, keeping in mind that in the reference scenario there is no prospect of the entry of new gas pipelines with compression stations in Brazil.

7.3.2 THERMOELECTRIC DEMAND

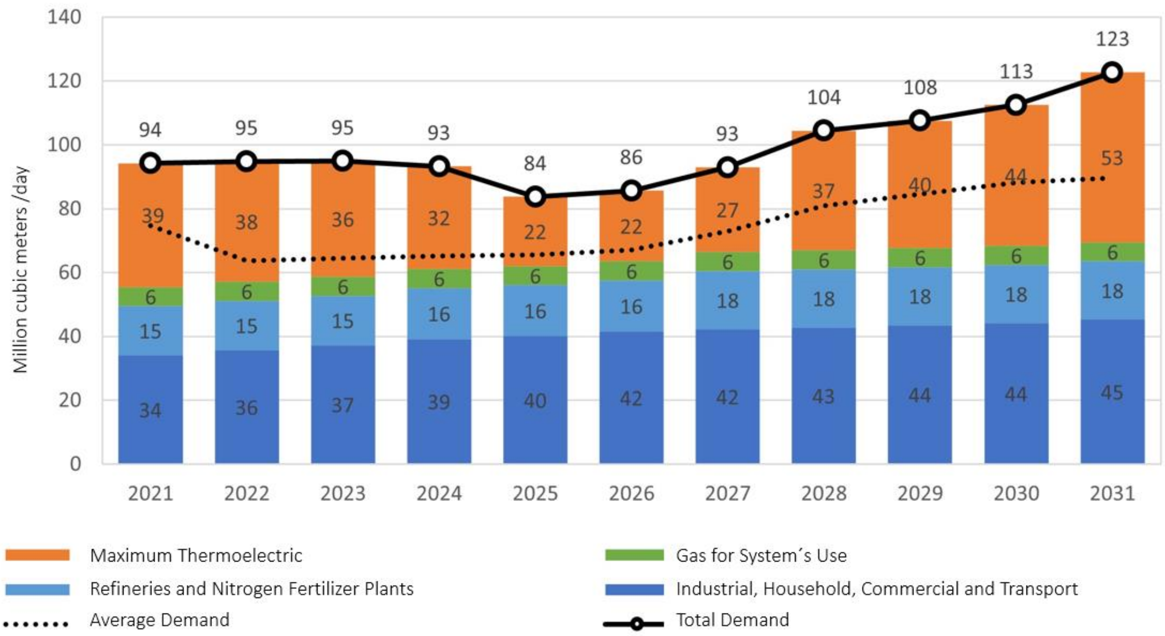
The demand for natural gas for thermoelectric plants considers the operation of existing facilities, the departure of UTEs due to the end of the contracts within the timeframe of the study, and the contracting of new UTEs as indicated in Chapter 3. For balance sheet purposes, the maximum volumes that can be consumed by the UTEs if they are dispatched are considered; their consumptions in the average dispatch situation are also presented for comparison purposes.

Over the next decade, the following plants are expected to start operating: Marlim Azul, GNA II, Barcarena, Ocelot, Prosperidade II, among others (MME, 2021). The winning UTEs of energy auctions in 2021 are also foreseen. It should be noted that thermoelectric demand also includes indicative volumes that are not yet related to specific projects, since they deal with possible projects that have not yet been the subject of auctions for the supply of electricity. Such indicative UTEs are not considered for the transmission gas pipeline network's simulation, since they do not have a defined location, being considered as a premise that they will be installed where there is transmission capacity available in the future or will be related to new infrastructures for their service. This is the case of thermoelectric plants expected to comply with the provisions of Law 14.182/2021.

7.3.3 DEMAND FORECASTS

The natural gas demand forecast was calculated by adding the non-thermoelectric demand forecasts to the thermoelectric demand forecasts. The demand forecast in the ten-year period, for the Integrated Network, is presented in Chart 7 - 2, as well as the demand perspectives considering average dispatch, for comparison.

Chart 7 - 2: Demand (Integrated Network)



Source: Prepared by EPE.
Note: The maximum thermoelectric demand refers to the existing thermoelectric power plants, also including the contracts' ending over the next decade, as well as new projects' contracting on an indicative basis.

Between 2023 and 2025, the maximum demand shows a reduction of around 10% due to existing UTEs contracts' ending and the time necessary for new UTEs to start operating, although there is an increase in non-thermal demands in this period, showing a resumption from 2025 associated with rehiring or contracting new, more efficient UTEs. At the end of the decade, the ratio between the average demand and the maximum demand has increased in relation to historical values, due to UTEs' entries with higher inflexibilities percentages.

This scenario may change if new demands or complete isolated systems become connected to the integrated network through gas pipelines or if final investment decisions concerning large new natural gas projects happen. This study's reference scenario was based on main natural gas sector players' data and contributions.

7.4 Supply

The Brazilian natural gas supply comes from three main sources:

i. national production;

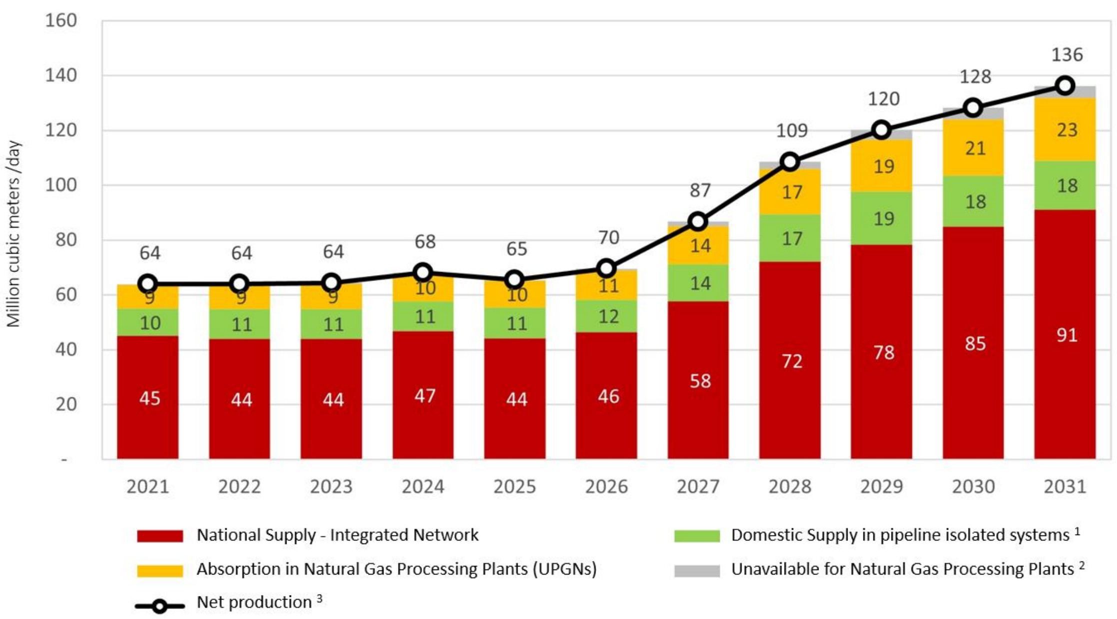
ii. imported through international gas pipelines; and

iii. imported as LNG trough regasification terminals.

7.4.1 DOMESTIC SUPPLY

Based on the forecasts of Net Natural Gas Production (see Chapter 5), the potential domestic supply was calculated considering the natural gas' processing, using the methodology described in EPE (2016). Chart 7 - 3 presents schematically the results of the potential supply available to the national pipeline integrated network based on the forecasts of net production.

Chart 7 - 3: Domestic Net Production and Potential Natural Gas Supply



Source: Prepared by EPE.

Notes: [1] National natural gas production in Amazonas and Maranhão States' systems that are not connected to the national pipeline integrated network; [2] Operational transfers in E&P units and thermoelectric generation at the wellheads; [3] Consumption in E&P, burning, losses and injection are already discounted from Gross Production.

Gross production of natural gas forecast for the next decade has considerable volumes from the pre-salt, which include higher consumption for the operation of compressors and production units, in addition to greater injection to recover the pressure of the reservoirs and injection of CO_2 after the fluids' separation. These factors contribute to the natural gas production's small variation from 2021 to 2025, despite the natural gas' gross production increase, presented in Chapter 5. The net production's increase does not follow the gross production's increase, because in the first half of the decade a considerable part of the natural gas production is destined to E&P activities such as consumption, flaring and injection.

Regarding the projected net production, a volume of around 64 million m³/day was estimated in 2021, reaching a volume of 136 million m³/day in 2031. The potential supply (calculated from net production, discounting the absorption shares in natural gas processing plants – UPGNs - and the volumes not available for shipment to these units) projected from the integrated network varies from 45 million m³/day in 2021 to 91 million m³/day in 2031. A sharp growth in the natural gas supply from 2026 onwards should be highlighted, which is justified by the expectation of significant production in the post-salt of the Sergipe-Alagoas Basin, in addition to the pre-salt in the Campos and Santos Basins.

7.4.2 IMPORTED SUPPLY

The imported supply covers both volumes supplied by international gas pipelines and LNG terminals. Regarding the first, only imports through GASBOL, which enters Brazil through the municipality of Corumbá/MS, were considered to reach the demand of the integrated network, since the other volumes are restricted to pipeline isolated systems.

The volume imported from Bolivia considered the maintenance of the maximum value, that is, 30 million m³/day until 2031. It should be noted that, in addition to Petrobras, it was considered that a part of these 30 million m³/day will be contracted by other companies with Bolivian producers, as discussed in EPE (2017) and due to later events such as the advance in negotiations of CDLs and Brazilian companies with Bolivia, in addition to Petrobras' waiver of exclusivity in loading GASBOL with a commitment to sell part of the imported volumes at the border (ANP, 2019a).

Regarding the LNG imports, only the three regasification terminals already connected to the integrated transmission gas pipeline network were considered during the natural gas' balance estimate to the network, allowing the directing of regasified LNG loads to the market. It was considered that the Baía de Todos os Santos Terminal, in Bahia State, has a regasification capacity of 20 million m³/day and that the Pecém Terminal, in Ceará State, has a regasification capacity of 7 million m³/day. The Guanabara Bay Terminal, in Rio de Janeiro State, has a 30 million m³/day capacity after its expansion (PETROBRAS, 2020a). The Porto do Açu and the Barra dos Coqueiros Terminals are both in operation and each one has a 21 million m³/day regasification capacity, but they are not yet connected to the national pipeline integrated network. However, regarding the Barra dos Coqueiros Terminal, it will be able to connect to the network as of 2023 (SEDETEC, 2021). In addition to the existing and planned terminals, the entry into operation of new terminals in the ten-year timeframe is compatible with sensitivity analyzes carried out by EPE.

It should be noted that the marine regasification terminals are the structures responsible for sending the regasified gas to the coast and are therefore independent facilities from the regasification unit (FSRU). These may have their contracts terminated or renewed depending on the need for regasification over the timeframe of the study, which also includes the contracted FSRUs movement in case it is necessary to provide gas to consumers near a specific terminal.

The natural gas imports through the Lateral-Cuiabá pipeline, in Mato Grosso State, and Uruguaiana/RS-Porto Alegre/RS pipeline (stretch 1) may serve mainly the Governador Mário Covas and Uruguaiana thermoelectric power plants, respectively. Therefore, as already mentioned, the volumes from these two gas pipelines were not considered to reach the national demand in the integrated network. Likewise, the potential supply from the Urucu/AM and Santo Antônio dos Lopes/MA processing plants are not accounted in the integrated network, since they serve their respective isolated systems.

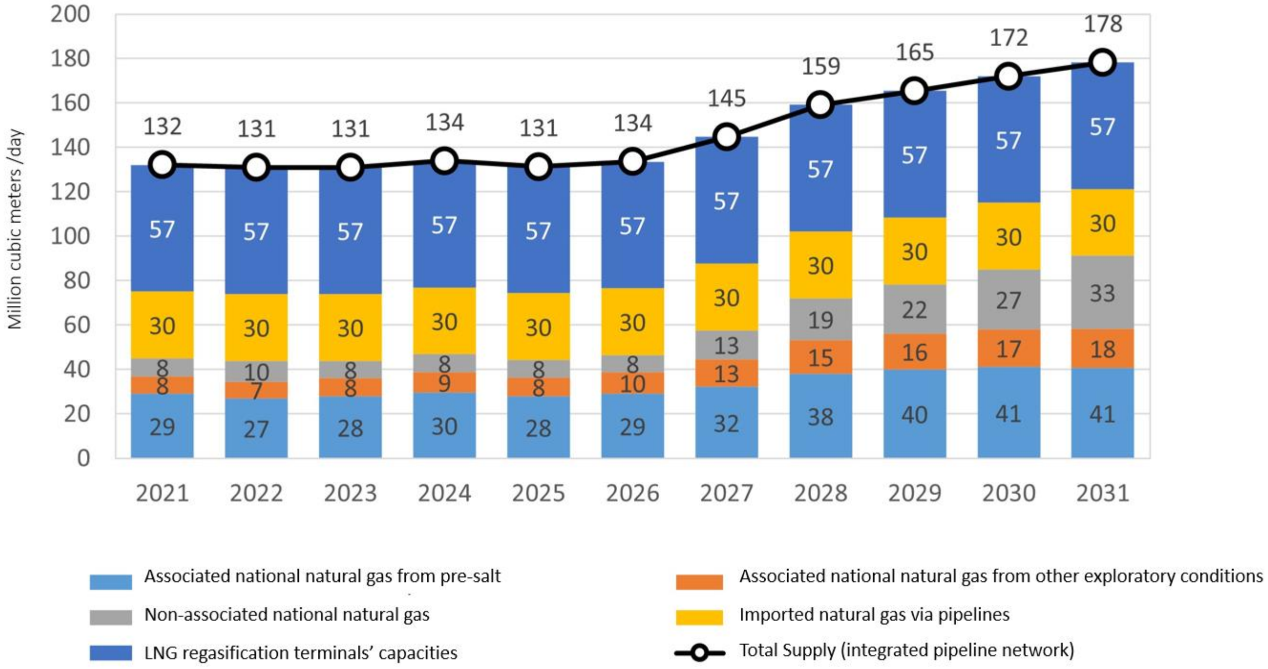
The LNG regasification terminals in Barra dos Coqueiros/SE, Porto do Açu/RJ and Barcarena/PA were not considered to reach the demand of the integrated network, since their interconnection to it, as previously mentioned, will depend on companies' commercial strategies. If these projects become reality, they may increase the potential supply for the they may increase the potential supply for the integrated network.

With the greater opening of the Brazilian natural gas market, EPE analyzed some pipeline alternatives to connect isolated systems to the network and published the results in the document named Indicative Plan for Transmission gas pipelines - PIG (EPE, 2019a and 2020c). EPE also studied possibilities to deliver natural gas through virtual gas pipelines and/or cabotage (EPE, 2020a; EPE, 2020b). Therefore, depending on market conditions, new supplies may be available to serve the integrated network within the studied timeframe, such as terminals already in operation, but not yet connected, as well as the future LNG terminals' connections.

7.4.3 POTENTIAL SUPPLY FORECAST

The forecast of the total potential natural gas supply was calculated by adding the forecasts of potential national supply to the volumes related to LNG and gas pipelines imports. The forecast of Potential Supply in the ten-year period, for the Integrated network, is presented in Chart 7 - 4, in terms of associated and non-associated national natural gas or imported.

Chart 7 - 4: Potential Supply (National Pipeline Integrated Network)



Source: Prepared by EPE.

Note: The potential volumes presented will be used to the extent necessary to reach the expected demand; it was considered that Baía de Guanabara/RJ, Baía de Todos os Santos/BA and Pecém/CE Terminals have regasification capacities of 30 million m³/day, 20 million m³/day and 7 million m³/ day, respectively.

The potential supply remains practically stable over the first half of the studied timeframe, increasing between 2026 and 2031 due to higher offshore associated and non-associated productions. Initially, it is observed that the increases in national supply result from an increase in the production of associated gas (pre-salt and non-pre-salt) and, later, from a significant increase in non-associated national gas. Throughout the study timeframe, there is an increase in the associated gas national production, mostly from the pre-salt, whose contribution reaches 83.5% in 2026 and drops to 64% in 2031 with the increase in production from Sergipe-Alagoas Basin and non-associated gas from the Pre-Salt.

Considering the importance of Pre-Salt's natural gas supply to the national market, EPE prepared a sensitivity analysis on the existing and planned outflow infrastructures in order to verify the need for additional investments in new infrastructures to guarantee the flow of net production to the coast during the next 10 years. **Box 7.1** describes the sensitivity analysis' results, considering such assumptions.

Box 7 - 1: **Sensitivity results about the pre-salt's natural gas flowing facilities**
Considering the Pre-Salt's natural gas net production, the study focused on the time when the existing and under construction facilities would be sufficient to outflow the natural gas. The maximum authorized flow capacities for

Box 7 - 1: Sensitivity results about the pre-salt's natural gas flowing facilities

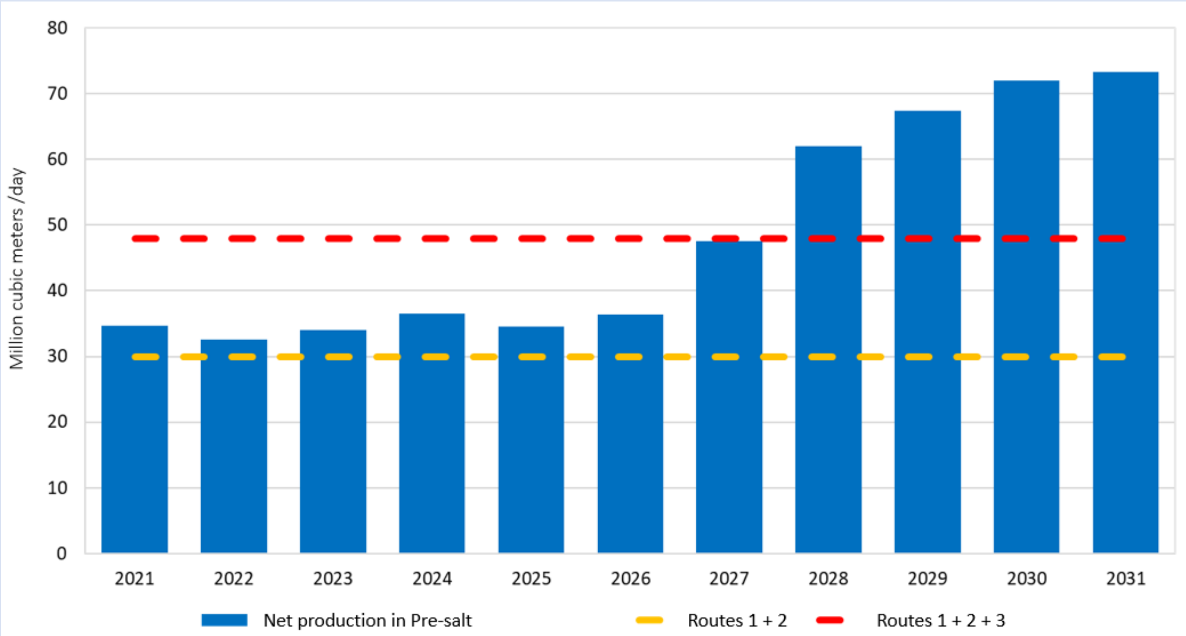
Routes 1 and 2 gas pipelines were considered: 10 million m³/day and 20 million m³/day, respectively (ANP, 2019b). For the Route 3 gas pipeline, which is expected to be completed in 2022, the maximum flow capacity of 18 million m³/day was considered (Petrobras, 2021). Chart 7 - 5 represents the volumes of net pre-salt natural gas production together with the limits of the maximum flow capacities of only Routes 1 and 2 as well as Routes 1, 2 and 3.

With Route 3 pipeline's entry, there will be sufficient flow infrastructure to flow production until 2027, this last year being very close to the capacity limit of the three routes together. From the year 2028, if all the planned productions come to fruition, there will be a need to expand the outflow infrastructure with the addition of new routes. This increase in expected production is related to Pre-Salt's associated and non-associated volumes.

This result agrees with the alternatives proposed in the Natural Gas Processing and Outflow Indicative Plans (PIPE) published in 2019 and 2021 for the Pre-Salt areas. Noteworthy, it is necessary that the infrastructures should be constructed within 7 years to fully reach the expected natural gas volumes. So, the final investment decisions need to be taken quickly to ensure their operability as early as 2028.

Therefore, in this Ten-Year Plan, it is possible to notice the investments' need in the construction and expansion of flow and processing infrastructures.

Chart 7 - 5: Net pre-salt production and flow capacities of Routes 1, 2 and 3 pipelines



Source: Prepared by EPE.

The natural gas supply (associated or non-associated national, imported via gas pipelines or via LNG) depends on factors such as the flexibility required by consumers, the need for firm contracting required by the suppliers, and the prices which will be negotiated depending on the constraints. In the case of imports via GASBOL, the service may also have different flexibility characteristics (take-or-pay), as mentioned above.

7.5 Balance

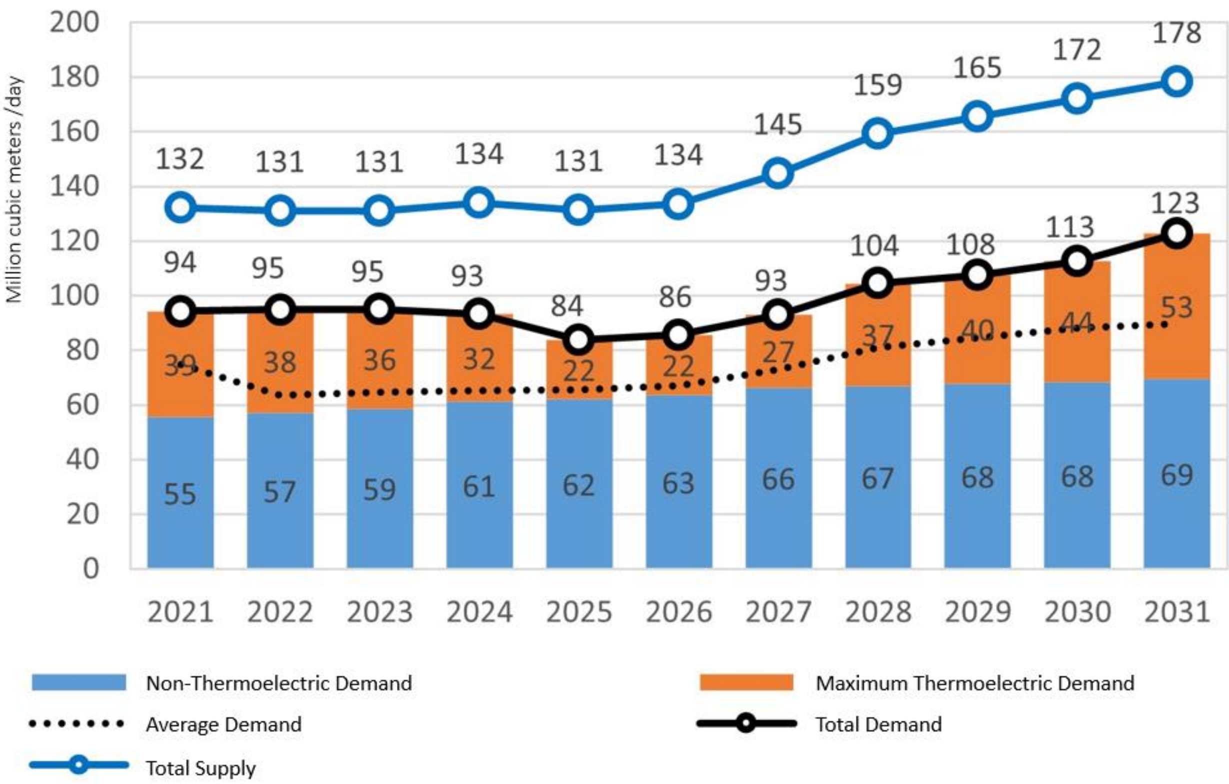
In this section, the natural gas balance of the integrated network is presented, based on the supply and demand scenario projected for the areas in its zone of influence. Isolated systems, such as Urucu-Coari-Manaus, Maranhão, Lateral Cuiabá, TSB stretch 1, Porto Sergipe and Porto do Açu are excluded from the analysis. Chart 7 - 6 illustrates the natural gas balance of the Brazilian integrated network.

The natural gas supply of national origin in the integrated network, detailed in Section 3, varies between 2026 and 2031, caused by the increase in the production of associated and non-associated gas, mainly offshore. Thus, the total supply shows a growth of approximately 3% per year in the decade.

The total gas demand grows by approximately 3.5% per year in the period. Non-thermoelectric demand includes demand from the industrial, household, commercial and transport sectors, which grows gradually and demand from refineries and fertilizer plants, which increases in 2024 with the resumption of FAFEN- PR and in 2027 with the entry of the Nitrogen Fertilizer Unit - UFN Três Lagoas/MS.

The national pipeline integrated network's balance could be more positive if at least part of the indicative thermoelectric plants were located in isolated systems associated with new own supplies such as LNG terminals, or if the Barra dos Coqueiros /SE or Porto do Açu/RJ LNG Terminals were connected to the integrated network (since they are less than 50 km from the existing pipelines), or if Barcarena/PA Port and Terminal Gás Sul/ SC, when constructed, become connected to the pipeline network.

Chart 7 - 6: Natural gas balance for the National pipeline integrated network



Source: Prepared by EPE.

Notes: The total supply (potential) refers to the maximum volume available, being used to the extent necessary to reach the expected demand and new projects that may be announced within the study's timeframe; The Average Total Demand represents the sum of the various demand parcels considered in EPE's studies: (i) local gas distribution companies, (ii) refineries and petrochemicals, (iii) fertilizer plants, (iv) expected consumption of natural gas-fired power plants and (v) expected consumption of bi-fuel thermoelectric plants operating on natural gas (EPE , 2016).

The **Box 7.2** provides a sensitivity analysis in case new non-thermoelectric and thermoelectric demands sign competitive contracts with new suppliers that will start to operate in the domestic market after the New Gas Market Program objectives' achievement.

Box 7 - 2: Additional supply and demand: Novo Mercado de Gás (New Gas Market) Program

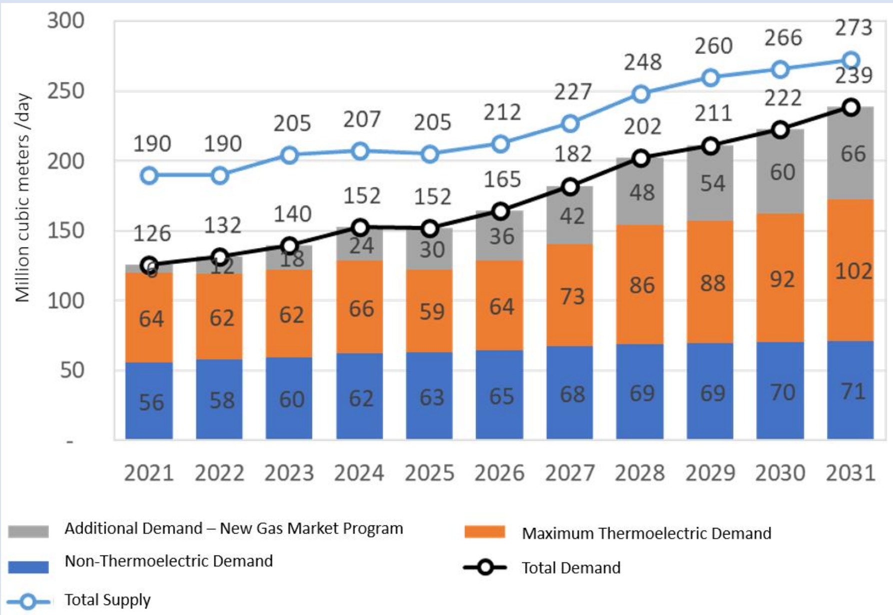
In addition to the reference supply and demand presented, which refer to the case where the foreseen, announced, and indicative investments will be carried out within the timeframe of the study, it was sought to estimate which additional natural gas' volumes could become available with a greater market's opening promoted by the New Gas Market Program.

The study considered that the Brazilian natural gas sector will tend towards greater integration over the decade, either through virtual gas pipelines (with compressed or liquid natural gas' flow) or through physical flow via pipelines, according to each case's feasibility. As for the national supply, the processing of the additional volumes of Net Production estimated in **Box 5.1** (Chapter 5) was considered in this study. Regarding the international supply, the total import capacity of international transmission gas pipelines, existing and future LNG Regasification terminals were considered in the methodology.

On the non-thermoelectric demand side, hypothetical projects were studied that could be built using considerable natural gas' volumes at competitive prices as new nitrogen fertilizer units (with potential to reduce imports) and new methanol production units (which could be an advantageous complement to the increase in biodiesel production by methyl route). In 2031, the results indicated an additional demand of 22 million m³/day. The existing projects' conversion to natural gas located up to 100 km from the current transmission gas pipeline network represents 11 million m³/day in 2031. These undertakings are related to the chemical industry, ceramic production units, large refrigerators (which could be converted to gas absorption cycles), grain drying, pulp and paper plants, among others. In the case of thermoelectric demand, the adoption of cogeneration was considered in projects that already have small diesel electric generators approved by ANEEL and are less than 100 km from the existing gas pipeline network, representing 33 million m³/day in 2031.

The **Chart 7 - 7** shows the supply and demand volumes considered in the NGM Program, considering the entire Brazilian territory, in systems that are currently isolated or connected to the pipeline network.

Chart 7 - 7: Brazilian total natural gas supply and demand according to the New Gas Market Program



Source: Prepared by EPE.
Note: Total volumes for isolated systems and integrated network; the connection between the systems can occur through virtual or physical gas pipelines, depending on each case's feasibility.

7.6 Simulations for the National pipeline integrated network

This section aims to present the results of the thermofluid-hydraulic simulations carried out for the evaluation of the natural gas transmission pipeline network. The years 2022, 2027 and 2031 were simulated according to the following assumptions:

• domestic supply volumes, imported from Bolivia (maximum 30.08 million m³/day) and LNG imported through the Guanabara Bay (TBGUA - RJ), Todos os Santos Bay (TRBA - BA) and Pecém/CE Terminals using, at most, their nominal regasification capacities authorized by ANP;

• non-thermoelectric demands for natural gas are considered (downstream demand and other demands from local distribution companies - CDLs);

• volumes referring to the System Usage Gas were not considered;

• the maximum thermoelectric demands are considered, including bi-fuel thermoelectric plants operating on natural gas. In relation to these demands, for the last years, plants that would terminate their contracts before the end of the ten-year period were also considered;

• indicative thermoelectric plants were not considered, because their locations in the pipeline network are not defined and will depend on the capacities availabilities for handling and delivering natural gas;

• infrastructures under construction and indicative are considered from their respective years of entry into operation;

• Porto do Açu/RJ, Porto de Sergipe/SE and Barcarena/PA were not considered connected to the national pipeline integrated network, because they do not have yet final investment decisions about this subject.

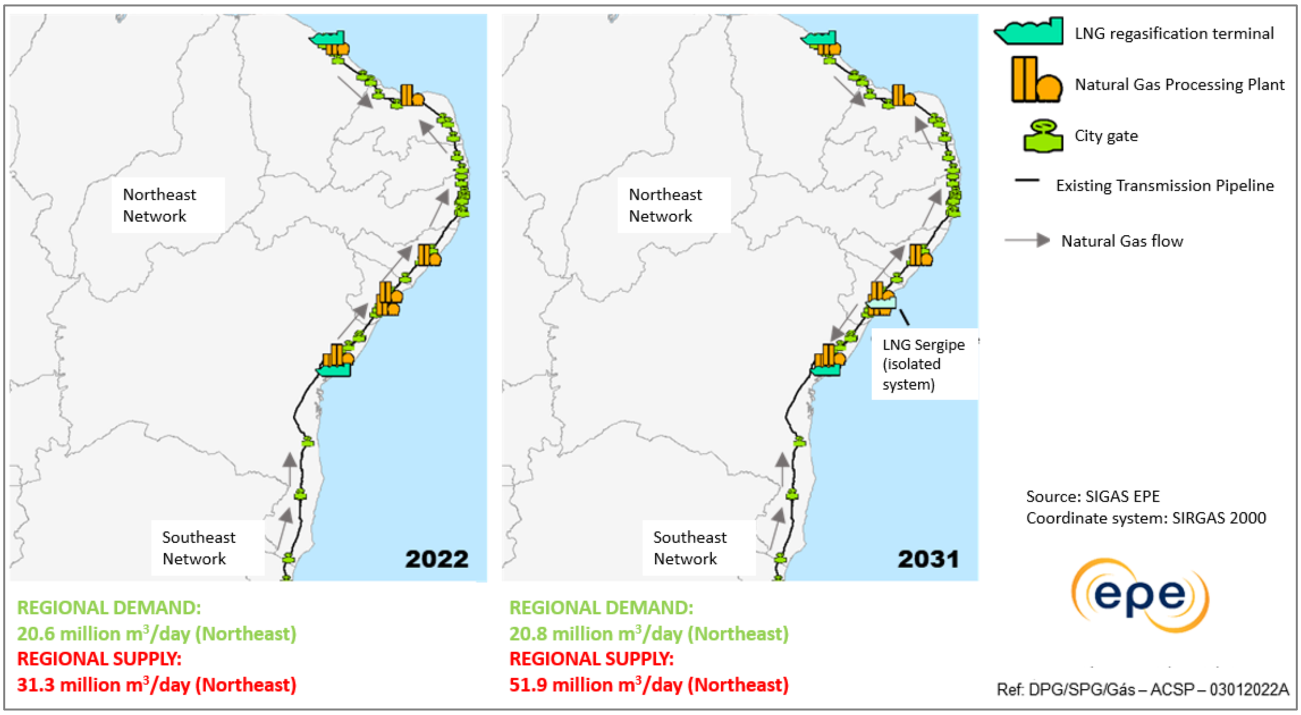
Some projects may impact the pipeline´s network simulations and their probable start-up years are the following: UFN III/MS in 2027, UPGN in the Gaslub Itaboraí Complex in 2022 and FAFEN/PR in 2024.

Next, the particularities of each subsystem will be presented, defined as segments per region of the integrated network.

7.6.1 NORTHEAST NETWORK

The simulation’s base case study considered the current transmission pipeline network and disregarded the LNG terminal and Porto Sergipe I Thermoelectric Power Plant, both located in Barra dos Coqueiros/SE as they are systems not interconnected to the network. **Figure 7 - 3** represents the simulated system considering the maximum potential supply available and the maximum demands.

Figure 7 - 3: **Boundary conditions (potential supply and maximum demand) for Northeast natural gas pipeline network's simulation in 2022 and 2031**



Source: Prepared by EPE.
Note: The Barra dos Coqueiros/SE LNG Terminal and its associated thermoelectric plant were not considered in the national pipeline integrated network's simulations, because they are considered part of an isolated system.

As can be seen in **Figure 7 - 3**, the sum of potential supplies is higher than the maximum demand projected for the period, indicating that the demands of the Northeast could be met by the supplies available in the Region in all the simulated years.

In the reference case, which includes LNG imports through existing terminals, there was no need to move natural gas from the Southeast to the Northeast network. However, according to the carriers' operational decisions and some fields' production fluctuations, gas flows between regions may occur during each year.

It is noteworthy, in 2027, the significant natural gas supply's increase in this region. Despite the considerable reduction in production from the fields that have the gas processed in Bahia's UPGNs (Candeias and Vandemir Ferreira Station), the deficit is compensated and overcome by the additional supply in Guamaré, Catu and, mainly, Atalaia the UPGNs. The higher projected supply of the latter is a consequence of the production expectations of the SEAL Basin starting in 2025. To enable the injection of these resources into the transmission network, if there is a demand for it, it would be necessary to expand various infrastructures, mainly gas pipelines close to the Atalaia/SE UPGN.

In the case of UPGNs, to promote this increase in production, a possible expansion of the Atalaia Processing Pole or the construction of a new UPGN in the region is expected. As for the existing gas pipeline network, these gas pipelines currently do not have the capacity to handle the expected increase in gas supply and, therefore, should undergo adjustments.

However, expansions depend on the demand existence that justify the investment. If this does not become true, an alternative solution would be the liquefaction of part of this increase in gas supply in liquefaction units for export or cabotage to other regions.

Regarding the thermofluid-hydraulic simulations for this subsystem, there were no infrastructure restrictions to reach the projected demands.

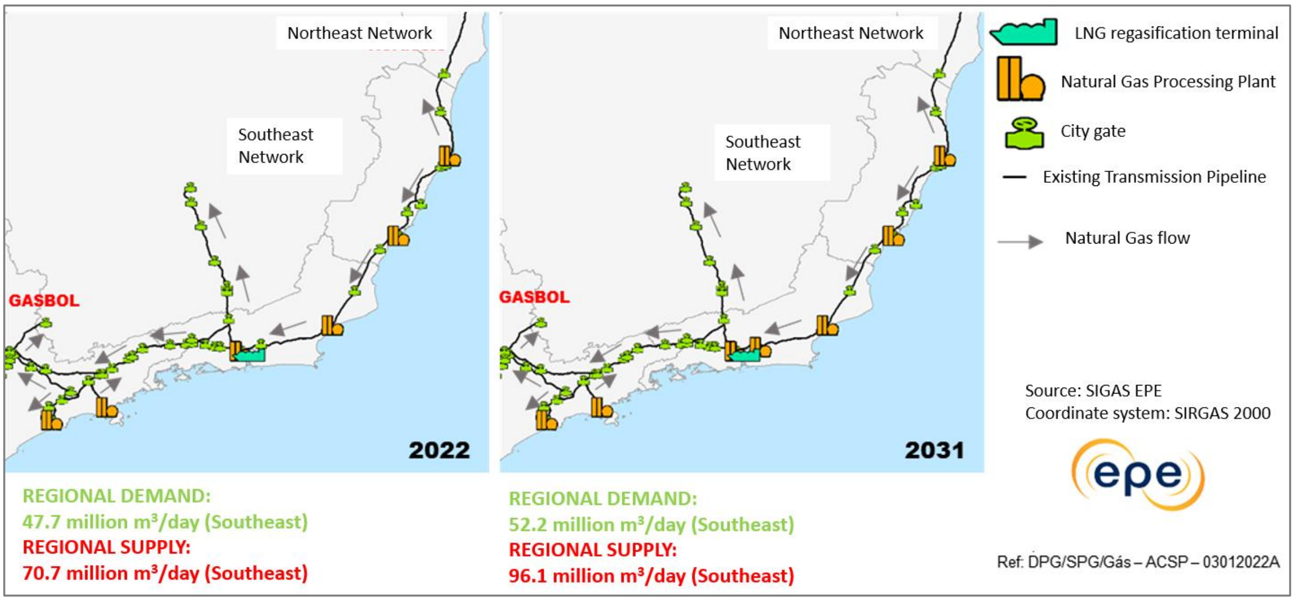
In addition, there was a restriction to greater use of gas from the Pecém LNG terminal, with no transport capacity in the GASFOR and Nordestão gas pipelines for gas flow when using this terminal's maximum regasification capacity. It is noteworthy, however, that the gas production projected for the SEAL Basin from 2025 onwards would minimize possible impacts on serving areas further away from the Pecém Terminal. However, if there is an interest in minimizing the LNG consumption in this subsystem or even not using the Pecém Terminal anymore, this restriction would be present again, which would prevent the shipment of gas from the SEAL Basin region to the northernmost region of the Northeast network.

As a result of the supply increase in the Northeast, the region will tend to become more independent in terms of natural gas, requiring imports only with the aim of balancing the network.

7.6.2 SOUTHEAST NETWORK

The base case study considers the Itaboraí/RJ-Guapimirim/RJ gas pipeline and Gaslub Itaboraí Complex UPGN entries in 2022, adding a new supply point in the network. It was considered that the Porto do Açu LNG Terminal and the UTEs GNA I and II, located in São João da Barra/RJ, constitute systems not interconnected to the integrated network. **Figure 7 - 4**, below, allows the visualization of the simulated system considering the maximum potential supply available and the maximum demands to be reached.

Figure 7 - 4: Boundary conditions (potential supply and maximum demand) for Southeast natural gas pipeline network's simulation in 2022 and 2031



Source: Prepared by EPE.
Note: The LNG terminal in São João da Barra/RJ and the associated thermoelectric plants were not considered in the national pipeline integrated network's simulations, because they are considered part of an isolated system.

As can be seen in **Figure 7 - 4**, both the year 2022 and 2031 present forecasts of potential supply higher than the maximum expected demand and, therefore, in principle, it would not be necessary to send gas from the other integrated network's subdivisions (Center-West/SP/South and Northeast) for the Region. In fact, it is expected that the Southeast will become an exporting region, considering the expected increase in natural gas production, mainly from pre-salt fields.

The thermofluid-hydraulic simulations' results indicated that no infrastructure restrictions were identified in this region of the integrated network. Additionally, it is noteworthy that the total supply of this subsystem is sufficient to reach the projected demand.

Considering the volume of 30.08 million m³/day for the supply coming from Bolivia through GASBOL, it is noteworthy that, if this premise is not materialized, there is still the possibility of surplus supply available in the Southeast Region to reach the GASBOL pipeline's demand. One of the possibilities indicated by the simulation to send gas from the Southeast Region to GASBOL would be through the interconnection in Paulínia/SP.

7.6.3 MID-WEST/SP/SOUTH NETWORK

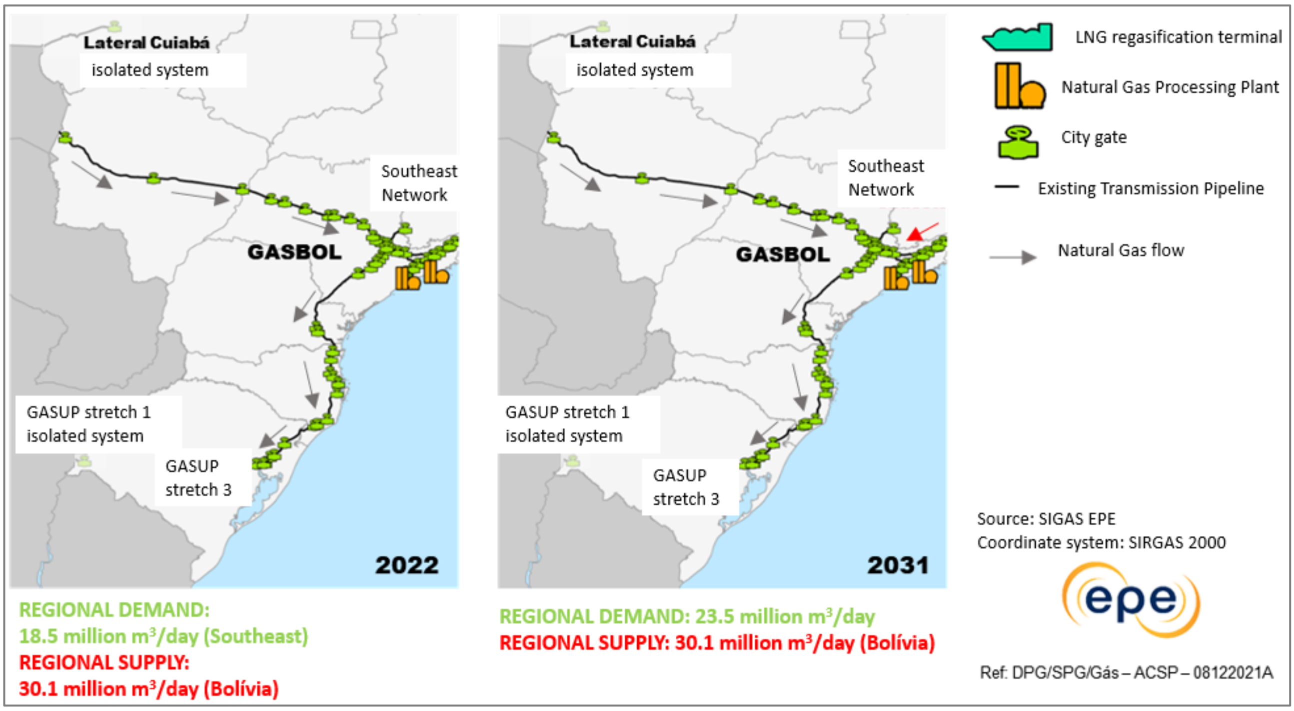
This network comprises the GASBOL and Uruguaiana-Porto Alegre stretch 3 (GASUP) gas pipelines. The first has telescopic characteristics, characterized by the reduction in diameter along its length, especially in the south stretch. For this reason, considerable load loss is observed during the natural gas flow, especially when associated with high flow rates, which can generate restrictions in reaching demands. GASUP (Stretch 3) is responsible for delivering gas at Triunfo/RS, after the natural gas' custody transfer between TBG and TSB companies.

Unlike other regions, the Mid-West/SP/South pipeline network does not currently have a domestic natural gas supply or even LNG terminals present in this subsystem that allow its demands' achievement. In this way, all its service is carried out using Bolivian gas imported through GASBOL, in addition to the possibility of receiving gas from the Southeast subsystem.

Although in this PDE cycle gas consumption was not considered by UTE Sepé-Tiaraju/RS and, therefore, no service restrictions were observed in the final stretch of GASBOL, it is known that, if the UTE and the Petrochemical Complex of Triunfo/ RS need to operate simultaneously at maximum capacities, these restrictions would occur. Additionally, if there is the inclusion of an indicative supply point close to REFAP (potential supply of domestic gas from the Pelotas Basin), the restrictions would be reduced due to the greater natural gas supply in GASBOL´s final stretch.

This section's capacity expansion through the addition or displacement of compression stations, associated or not to loops in the existing network, would also allow an increase in the fulfillment of this Region demands. Another possibility would be the installation of new LNG regasification terminals in the South. In this sense, the potentials of Santa Catarina and Paraná's LNG regasification terminals stand out. **Figure 7 - 5** allows the visualization of the simulated system, considering the maximum potential supply available and the maximum demands to be reached.

Figure 7 - 5: Boundary conditions (potential supply and maximum demand) for GASBOL and GASUP pipelines' simulation in 2022 and 2031



Source: Prepared by EPE.
Note: Lateral Cuiabá and GASUP (stretch 1) gas pipelines were not considered in the national pipeline integrated network's simulations, because they are considered isolated systems.

7.7 Investments

The estimated and indicative investment costs were estimated for the timeframe from 2022 to 2031, and the planned investments include the projects related to the infrastructure sector already announced, and the indicative projects are those foreseen as important for the expansion of the sector. Noteworthy, some investments had entry dates assumed by EPE, with no official timetable definitions yet. In addition to UPGNs and LNG terminals, indicative investments were estimated in outflow gas pipelines (related to new fields that will come into production in the post-salt and pre-salt in upcoming years) and in possible new transmission gas pipelines to connect future LNG terminals to the integrated network, or to serve regions where there is still no natural gas supply.

Projects in the order of BRL 6.00 billion for the Rota 3 gas pipeline and BRL 2.39 billion related to the Natural Gas Processing Unit at the Gaslub Itaboraí Complex/RJ installation were considered (total value of the projects, which already are in the final stages of construction). Although, in PDE 2030, the outflow gas pipeline and the UPGN associated with UTE Marlim Azul, in Rio de Janeiro, were considered as planned projects, both were disregarded in this PDE cycle. This stems from Shell's option to flow the gas to Cabiúnas UPGN and then send this gas to the natural gas processing unit (Macaé City Hall, 2021).

Also, there is a forecast for the implementation of the transmission gas pipeline called Itaboraí/RJ-Guapimirim/RJ that will connect the UPGN of the Itaboraí Gaslub Complex to the Cabiúnas/RJ-REDUC/RJ gas pipeline (GASDUC III) in the vicinity of the Guapimirim/ RJ. This transmission gas pipeline, currently being evaluated by the ANP to define the granting process, has 11 km length, 18.2 million m³/day nominal capacity, 24 inches nominal diameter and an estimated cost of BRL 126 million. As an indicative gas pipeline, the construction of the Guamaré/RN-Pecém/CE gas pipeline (GASFOR II) was considered, a reinforcement of the transmission capacity in the integrated network's northern end. The gas pipeline, with a length of 210 km and a diameter of 20 inches, also aims to divert the GASFOR route from a densely populated area in the municipality of Fortaleza/CE, which, for safety reasons, required reducing the gas pressure in this stretch. The project of this gas pipeline is divided into two stretches: Horizonte-Caucaia and Horizonte-Guamaré. The Horizonte-Caucaia stretch has started in previous years, so its cost estimate is around BRL 230 million. Additionally, in August 2021, Transportadora Associada de Gás (TAG) made its application for an Installation License (DOU, 2021).

In the case of indicative investments in outflow gas pipelines and UPGNs, a new gas pipeline and a new UPGN were considered in the reference scenario to outflow and process natural gas from the Sergipe-Alagoas Basin. The case called "New Gas Market" includes the projects described at the publication named Indicative Plan for Flow and Processing – cycles 2019 and 2021 (EPE, 2019b; EPE, 2021c). They are located at Campos, Santos, Espírito Santo-Mucuri, Sergipe-Alagoas and Camamu-Almada Basins, in pre-salt and post-salt environments. Onshore projects in the Solimões and Parnaíba Basins were also analyzed. These publications studied natural gas pipelines connecting volumes to: the coast; to the existing flow network; to existing processing units; to offshore hubs and indicated possible new natural processing units.

The transmission gas pipelines considered in New Gas Market Case are those detailed in the publication named Indicative Plan for Transmission gas pipelines – cycles 2019 and 2020 (EPE, 2019a; EPE, 2020c) and studied new pipelines to serve new areas that still do not have a natural gas supply or to connect the supply from existing or future unconnected LNG terminals.

About the LNG regasification terminals' investment, the construction of a terminal is planned for the ten-year timeframe, in Barcarena/PA, in addition to three new indicative terminals: in São Francisco do Sul/SC, on the coast of Santos/SP and in Suape/PE. In view of the variety of possible LNG terminal configurations, this document considered the most common alternative - Standard Stacked Terminal (similar model of the Santos/SP and São Francisco do Sul/SC projects, for example) in order to estimate the average construction cost. In this configuration, it was also considered that this would be a terminal for private use, offshore, with Ship-To-Ship (STS) mooring and without the need for dredging or breakwater. An average distance of 5 km from the coast was also considered, which would require an underwater gas pipeline of the same length to send the regasified natural gas to the coast. Thus, it is estimated that each of the screened terminals would require investments of approximately BRL 350 million (base date December 2020), which include only the pier with the necessary equipment, in addition to the gas pipeline and other auxiliary facilities - for more details on the pricing of LNG terminals in Brazil, it is necessary to read the Indicative Plan for LNG Terminals – PITER. In New Gas Market Case, the entry of four new LNG terminals linked to other projects with thermoelectric or non-thermoelectric natural gas demand described in PITER (EPE, 2021d) was also considered. Therefore, a total investment of BRL 1.1 billion in indicative LNG terminals was estimated in the New Gas Market Case. However, it should be noted that these values can vary considerably depending on the characteristics of each specific terminal, as well as its technical configuration and associated port facilities.

The values of investments in outflow gas pipelines, UPGNs and transmission gas pipelines were analyzed at a conceptual level and may change within the indicated uncertainty degree. It is remarkable that the values for indicative projects (business as usual and New Gas Market) were calculated from the methodologies and tools developed by EPE.

Thus, **Table 7 - 1**, below, presents a summary of the estimated investments. If additional favorable conditions for Brazilian natural gas market, such as those in Law 14,182/2021 appears, then, they may promote an increase in estimated investment values, due to the possibility of including new projects, in addition to those considered in this document.

Table 7 - 1: Foreseen and indicative investments

Classification	Foreseen		Indicatives (*business as usual*)		Indicatives New Gas Market Case	
	Projects	**BRL bi**	**Projects**	**BRL bi**	**Projects**	**BRL bi**
Outflow gas pipelines [1]	1	6.00	2	6.58	19[4]	24.98
Transmission gas pipelines [1]	1	0.13	1	0.23	16[5]	48.64
LNG regasification terminals[2]	1	0.35	3	1.05	4	1.09
Processing plants and Hubs [3]	1	2.39	1	3.50	18	42.92
TOTAL	**4**	**8.87**	**7**	**11.36**	**57**	**117.63**

Source: Prepared by EPE.

Notes: [1] *Investments estimated by EPE using the gas pipeline cost assessment system – SAGAS; the cost estimate by EPE for indicative flow and transmission gas pipelines has a degree of uncertainty of -50% to +100% (AACE-18R-97); for scheduled transmission gas pipelines the uncertainty degree of the estimate ranges from – 7% to + 17% (AACE-18R-97); the costs of outflow gas pipelines do not include natural gas compressor units, which must be foreseen in the FPSO project.* [2] *Estimated based on costs of terminals deployed around the world, considering only the pier without the FSRU (which would be included as a charter in OPEX); the cost estimate by EPE for planned LNG terminals has a degree of uncertainty of -50% to +100% (AACE-18R-97).* [3] *Investment estimated by EPE using the UPGNs cost assessment system – SAUP only for indicative projects (EPE, 2018); the cost estimate by EPE for UPGNs and Hubs has a degree of uncertainty of -50% to +100% (AACE-18R-97). Includes the gas pipelines studied in PIPE 2019 and PIPE 2021.* [5] *Includes the gas pipelines studied in PIG 2019 and PIG 2020.5 Includes the gas pipelines studied in PIPE 2019 and PIPE 2020.* [6] *Includes the UPGNs studied in PIPE 2019 and PIPE 2021 and the Hubs studied in PIPE 2021.*

MAJOR POINTS OF THE CHAPTER
NATURAL GAS

- *Changes in the regulatory framework arising from the New Gas Market Program, mainly with new players' entry (for example using new LNG terminals) and with the increase in investments in the sector, may change the dynamics of the regional natural gas market and access from the domestic market to the LNG market.*
- *The price of natural gas related to LNG in Brazil will be affected by the price of the international market, becoming more influenced by Henry Hub in the short term and having its logic changed from the gas-oil competition to the gas-gas competition over the decade.*
- *The net production of natural gas will increase from 64 million m³/day in 2021 to 136 million m³/day in 2031. The projected domestic potential supply of the national pipeline integrated network will increase from around 45 million m³/day in 2021 to approximately 91 million m³/day in 2031.*
- *There is an increase in total gas production, and the pre-salt corresponds to 63% of domestic supply in 2031. In addition, at the end of the period, there was an increase in domestic production of non-associated gas from the Sergipe-Alagoas Basin.*
- *Investments in the construction of new infrastructure will be necessary to flow all the expected net production of the Pre-Salt from 2028 onwards.*
- *As for the Bolivia imports, the maintenance of the maximum volume of 30 million m³/day until 2031 was considered. The potential import of LNG in the integrated nework in 2031 will correspond to the installed capacity of the existing terminals, of 57 million m³/day, from 2021 to 2031, in addition to 3 terminals (existing and planned) not connected to the national pipeline integrated network.*
- *There is a possibility to increase the natural gas demand beyond what was foreseen in the reference scenario, which may be due to the feasibility of new projects along the integrated network. Alternatively, excess volumes can be compressed or liquefied and moved to customers until larger transmission gas pipelines can become in operation.*
- *Considering the greater competitiveness of natural gas in the coming years, it may become feasible to connect isolated systems to the integrated network directly or indirectly (through virtual gas pipelines). The New Gas Market may encourage the connection of systems via road, rail, waterway (CNG or LNG) and/or gas pipeline modes, in addition to enabling new supply and demand projects.*
- *The forecast of investments related to the expansion of the natural gas infrastructure is around BRL 137.86 billion, of which around BRL 8.87 billion in planned projects and BRL 128.99 billion in indicative projects. Among the indicative projects, are terminals whose projects show progress in terms of final investment decision in addition to new ventures encouraged by the opening of the market with New Gas Market Program.*