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GAS REGULATION

Colombia

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Gas Regulation

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DOMESTIC SECTOR OVERVIEW

State of the market

Describe the domestic natural gas sector, including the natural gas production, liquefied natural gas (LNG) storage, pipeline transportation, distribution, commodity sales and trading segments and retail sales and usage.

Law No. 142 of 1994 restructured the legal framework for Colombian utilities, liberalising the natural gas market, enabling private investment and creating the Energy and Gas Regulatory Commission (CREG). As per this law, the Colombian natural gas sector value chain comprises:

- producers of natural gas or LNG importers;
- transporters from production sites and regasification plants to city gates;
- distributors of natural gas to final users; and
- retailers that sell to non-regulated users (large-scale users that consume more than 100,000 cubic feet per day (mcf/d) or the equivalent in cubic metres) and regulated users (mostly for residential consumption).

Nonetheless, it was not until 2016 that CREG enabled free price negotiations and created the role of the Natural Gas Market Manager (the Market Manager), a vital role performed by the Colombia Mercantile Exchange, which compiles, centralises and publicises the gas sector's transactional and operational information, thus optimising usage of the transportation and supply infrastructure. The Market Manager is also in charge of organising auctions in the secondary market to create liquidity and to link supply and demand. This will be qualified below when addressing market prices regulation.

Concerning production, Law No. 1360 of 2003 restructured Colombia's upstream oil and gas sector and created the National Hydrocarbons Agency (ANH) to promote private investment, reduce government take in the upstream market and allocate exploration and exploitation rights through a regulated auction bidding process.

ANH's last Colombia Field Auction Round was in December 2021, when 21 areas were awarded for exploration and production. Exploration has been declining since 2017 in a trend intensified after 2021 when the current government's policy allowed exploration only in land tracts contracted by ANH up to 2022. By 2023, there were only 51 exploration drilling works in fields covered by historical contracts (45.2% less than in 2022). This tendency remained in 2024 when only 34 exploration wells were drilled, and 2025's first semester stood at nine explorations. Similarly, 600 development wells were drilled in 2022, then dropping to 477 by 2024 and to only 61 in the first semester of 2025 (30.5% less than for the same period in 2024). Further contraction was reported in the second half of 2025, even though figures have not been consolidated yet. During 2024–2025, the number of active drills has remained at about 31 for exploration drilling and 81 for well reconditioning, which is still the lowest level since 2013–2014 excluding the pandemic.

Colombian proven natural gas reserves decreased 56% over the past 10 years. For December 2018, the total proven natural gas reserve was estimated at 3,782 giga cubic feet, then projected to provide nine years of self-sufficiency. ANH reported in May 2025 that reserves stood at 2,064 giga cubic feet in December 2024. That reserve would be exhausted within 5.9 years if national consumption remains at the current 960mcf/d and no gas is imported. Domestic production is projected to decrease substantially from its 2023 level of approximately 1,059mcf/d to 393mcf/d by 2030. In January 2024, national marketed production was 966mcf/d, which means a reduction of 5.3% compared to January of 2023 and 4.9% compared to December 2023. However, because 18.4% of national consumption is reported to have been using imported gas in 2025, national reserves could be exhausted at a later date at the cost of imported LNG. Daily importations of LNG have rapidly risen to a peak of 25% of gas supply offered in the market for April of 2026, reflecting that domestic production hit a low of 693 mcf/d for February this year. The projection now is that that LNG supply share will have to become larger in the short term once the effects of super El Niño come in October this year. But Colombia will still have only one LNG importation and 480 mcf/d regasification facility on the Caribbean cost (of which 400 mcf/d are committed to thermal plant supply until 2030), although a few LNG installations listed below are expected to be commissioned by 2027 with initial capacities that would add up to about 420 mcfd.

ANH also reported that contingent resources increased by 48% to 11,096 cubic feet in 2024, of which 67% are in the Caribbean Sea and 33% are on shore. These estimated figures remain unchanged. ANH and Ecopetrol are relying on some of these resources being soon upgraded into reserves. The Easter Caribbean offshore field called Sirius is estimated to have between 6 and 7 tera cubic feet and to be able to deliver 425mcf/d by 2029–2030. In fact, 249mcf/d was successfully committed on 12 December 2025 to be sold by the Sirius operators Ecopetrol-Petrobras to 17 buyers under the Firm Contract Subject to Conditions modality. Sixty-six such contracts were executed for 50, 86 and 113mcf/d to be sold in 2029, 2030 and 2031, respectively. Technical and regulatory challenges for this important deepwater finding, including an estimated 120 prior consultations with communities, remain to be conducted.

After drilling started on 11 November 2025, Ecopetrol reported a major finding called Copoazú 8km from Sirius in the same offshore block. It is reported to be the third most important discovery in Colombian history (Sirius being the first). However, its full dimension is yet to be established.

As for additional domestic gas supply potential, Ecopetrol reported in late 2024 two offshore explorations in the Caribbean. First, the Papayuela finding in the Sirius field, which even though was thought to yield 500mcf/d was recently assessed to technically be a dry hole. Second, the Caribbean Komodo field, which is expected to have an even higher yield operated by Oxy and Ecopetrol, has encountered delay for insurmountable environmental licensing requirements. The licence granted is being challenged in court by Anadarko due to the allegedly unprecedented requirement that each drilling will need an independent licence. Furthermore, the time window for a drilling ship to be on site has shifted to a provisional date, and thus drilling is not expected to begin in 2026.

The overall situation has become more compromised because Colombia's main independent gas producer Canacol, which supplies up to 17% of the national demand (10% in March 2026) – while undergoing creditors arrangement proceedings in Canada as well as reorganisation and restructuring proceedings respectively in the United States and Colombia – has filed a petition with the Alberta's Court of King's Bench for authorisation to renounce 19 gas supply contracts in Colombia due to not having gas to honour them before 12 clients. A main reason stated for this is that its explorations have not had the expected results.

The country relied on imported LNG for 18.4% of its natural gas consumption in 2025, and up to 84% may need to be imported by 2030 while domestic production recovers. Colombia's importation infrastructure will have to rapidly adapt to meet the imported volumes by expanding regasification facilities and transportation infrastructure on both coasts.

Imported gas supply is being made through the Caribbean coast Cayao LNG terminal, capable of regasifying 533mcf/d, of which 400mcf/d is to exclusively supply certain thermal generators on the Caribbean coast until 2031.

Over 14 new LNG facilities have been or may be contracted. The advance projects include Ecopetrol with contractor Puertos, Inversiones y Obras, conducting a project worth US$130 million (financial closing with the National Development Financier and BTG Pactual). This contractor's project company is Regasificadora del Pacifico SAS. A 145 cubic meters storage capacity FSU will be located at the Pacific coast city of Buenaventura, and iso-containers will be trucked inland to the Buga LNG regasification facility connected to the Natural Gas National Transportation System (SNT). The required delivery for 2026 is 60mcf/d, increasing to 120mcf/d at some later date. A supplementary 1.5mcf/d regasifying plant will be set in Buenaventura to meet regional distribution for half a million residential users.

Redundantly, the National Natural Gas Supply Plan includes a 400mcf/d LNG Regasification Facility at Buenaventura. However, despite two unsuccessful auctions (the latest was declared deserted in June 2023), and a third not having yet been convoked by the Colombian Ministry of Mines and Energy (MME)'s Mining and Energy Planning Unit (UPME), this Plan has still not been implemented. Other projects include:

- An Ecopetrol-Frontera facility at Cartagena, which has been contracted using Frontera's existing port infrastructure for commissioning a facility by late 2026 to initially deliver 126 and then up to 370mcf/d by 2028–2029. Ecopetrol closed commercialisation on 26 March 2026 with 13 buyers, including traders and thermal generators. It has also contracted the regasification service for a period of seven years. Ecopetrol mentioned on 18 March 2026 that it will prioritise this project, particularly after its Coveñas project has now been delayed.
- A TGI-Ecopetrol 130mcf/d facility close to the SNT's Ballena gas hub on the eastern Caribbean coast has a 10-year commitment for the FSRU, and its connection to Ecopetrol's offshore Chuchupa-Ballena line has been approved. However, the project is undergoing environmental approval proceedings with ANLA. There are now firm conditional supply commitments with final users. April or May is targeted for LNG tendering and commercial operation is targeted for January 2027.
- Amazon LNG is a joint venture between Retramar and Affinity Energy in a strategic alliance with cryogenised natural gas supplier Vitol. A 150mcf/d regasification terminal with two cryogenic regasification trains is expected to be commissioned by 2027 at Puerto Palermo on the east-central Caribbean coast near Barranquilla. Its gas will be trucked to a Promigas station on the SNT. The project is stated to now have detailed engineering, secured an EPC contract and attained environmental and port permitting, while financing for about US$150 million is being arranged through MUFB Bank.
- The Ecopetrol Coveñas facility on the western Caribbean coast has been approved by the Colombian environmental authority ANLA. It was expected to deliver 110 mcf/d by early 2027 with a projected final capacity of 400mcf/d by 2030. However, Ecopetrol

> has announced that the project has been de-prioritised because its connection request has not been answered by the transporter. The plan is to connect to the SNT using a reconverted oil line from Coveñas to the Ayacucho point on the Ballena/Barrancabermeja trunkline in northeastern Colombia.

A solution that has been considered is reactivating the 500mcf/d PDVSA pipeline from the Maracaibo gas fields in Venezuela to the Ballena hub. A gas transportation agreement has existed with Ecopetrol since 2007. Colombia stopped delivering gas through this line to Venezuela in 2019. Reactivating will now require a large maintenance or overhaul investment estimated at US$60 million over 18–24 months. Ecopetrol further says that it must be available sooner, together with the United States lifting related OFAC sanctions on Venezuela. On 13 March 2026, PDVSA said that it would rather rescind the contract because its terms are uneconomical considering the involved investment, and thus this is an unlikely though much publicised project.

However, the Colombian MME stated on 18 March 2026 that the eventual importation of Venezuelan natural gas prices could reconfigure Colombia's supply map, so as to deprioritise Sirius as Colombia's main option to meet its supply deficit. The Minister envisaged that Sirius and other offshore findings could thus become reserve or exportation projects regarding the Venezuelan supply. Moreover, he stated that Venezuelan gas importation would cause Colombia to need only one or two LNG regasification facilities rather than the multiple projects now under way.

Note that natural gas prices have been, and are still expected to be, volatile over the past two years, mainly because of the volatility of imported gas prices. Prices observed in the market following new contracts for the gas year commencing in December 2025 range from US$4.69 to US$11.81MMBtu/d for regulated or unregulated users. That is a substantial increase of between 9% and 48% over the past two years for unregulated users. The weighted average price for the same December 2025 contracts is US$9.05. Government-controlled Ecopetrol, which is the main producer-trader in the market, reports a weighted average price of US$6.50 for 2026, offering stability to residential users.

Also answering to Colombia's growing natural gas supply deficit, Colombian authorities have issued three sets of regulatory measures.

First, CREG issued two successive resolutions intended to provide marketing flexibility and efficiency for allocating available gas. In late 2024, it issued Resolution 102 009, modifying certain provisions in Resolution 186 of 2020 applicable to natural gas supply negotiations in the primary and secondary markets. Resolution 186 was the natural gas supply market framework regulation as amended until then.

CREG soon thereafter issued Resolution 102 015 on 30 January 2025 (the Resolution), which expressly abrogates Resolution 186 and its amendments. It defines the primary supply market as being where natural gas producers-marketers and imported gas marketers offer natural gas for sale to the fuel gas public service, and the secondary supply market as being where marketers and non-regulated users who have acquired supply of gas volumes in the primary market or gas supply rights in the secondary market may offer such volumes for sale.

The Resolution is now the frame regulation applicable to the Colombian natural gas wholesale market. The main changes and some restatements of prior regulations are as follows:

- Elimination of C1 (firm uninterrupted delivery with verified reserves) and C2 (firm portion and supplier option on variable portion) contracts and the annual auctions for these contracts.
- The inclusion of requirements to evidence physical backup for imported gas. An importer is considered to have physical backup when, at the time of offering supply for a given period, it has a contract guaranteeing access and the right to use international interconnection capacity or regasification infrastructure capacity. This enables marketing gas from the existing and future import infrastructure.
- The only types of supply contracts that may be transacted in the primary market are:

- firm supply contract with minimum payment of 95%, CF95;
- firm supply contract with minimum payment of 80%, CF80 (newly included by Resolution 102 015, whereby firm supply without interruptions and with minimum monthly payment of 80% is contracted for a set period, regardless of whether the gas is consumed or not);
- gas purchase option supply contract against exports, OCGX;
- contingency supply contract, CSC;
- conditional firm supply contract, CFC;
- gas purchase option supply contract, OCG;
- contract for the supply of total production available for sale in tests; and
- supply contract with interruptions, CSI.

All but the last type of supply contract above can be directly negotiated by the parties, provided that the Resolution's Title I's terms are observed. These terms are in general about the required structure and regulatorily required content of each contract as a condition of its registrability before the Gas Market Manager. Annex 1 of the Resolution explains the transactional and operational information required for contract registration with the Market Manager and market publicity needs. In the secondary market, only the following types of contracts may be agreed:

- contract for firm supply or with firmness guarantee, CF;
- conditional firmness supply contract, CFC;
- gas purchase option supply contract, OCG;
- gas purchase option supply contract against exports, OCGX;
- contingency supply contract, CSC; and
- supply contract with interruptions, CSI.

Even though Resolution 102 015 of 2025 does not explicitly list the types of contracts for which having physical backup is obligatory, this is implicit and necessary for the registration and operation of supply contracts in the primary and secondary markets. Resolution 102 015 of 2025 lists the types of contracts for which having physical backup is obligatory, this being necessary for the registration and operation of supply contracts in the primary and secondary markets. Physical backup is defined as the certified evidence that a producer has Natural Gas Reserves (defined as the proven or probable reserves certified by ANH), that a trader physically has natural gas or that a transporter physically has the transportation capacity to assume and comply with firm contractual commitments, or to ensure firmness from the moment deliveries begin until they cease.

Nine other changes made by the Resolution are:

1. Requirement for each source to report its total production available for firm sale. This includes the concept of "total production available for sale under testing", which is defined in the Resolution as the supply that the producer commits to deliver continuously and without interruptions during the field's extended testing period.
2. Definition of mechanisms for accessing essential demand (by the SNT's compressor stations, residential and small commercial users, natural gas fuelled vehicles and refineries excluding gas for their power self-generation). Resolution 102 015's Annex 8 sets the methodology for primary market sellers and buyers to prioritise essential demand supply when and if the Market Manager's commercial balance sheet shows deficit for a given standard market execution quarter.
3. Modification of contract duration, which changes from one, two or more years to one or more standard quarters (namely, December–January–February, March–April–May, June–July–August and September–October–November).
4. Flexibilisation of the periodic update of prices in initially agreed contracts. The equations for updating prices in contracts may be agreed by the parties applying frequencies of one standard quarter or more, or as freely agreed if the direct negotiation mechanism is used, devoid of competitive bidding by interested parties. Annex 3 of the Resolution provides an update of equations methodology that may be used by the parties at their discretion.
5. Elimination of auctions and introduction of direct negotiations for interruptible contracts in the primary and secondary markets.
6. Modification of the interruptible contract, establishing that it becomes firm on a daily basis when the following conditions are met simultaneously:

- during the nomination cycle of the day prior to the gas day, the buyer nominates a gas quantity, and the seller authorises the energy quantity to be supplied; and
- the supply source used has natural gas reserves.

7. For supply contract modalities involving imported gas, maintenance activities for import infrastructure will amount to 480 hours per year.
8. There is no breach of supply when the nominated gas is delivered, regardless of the supply source, as long as this does not generate additional costs for the buyer.
9. The Market Manager must perform the supply–demand balance for each of the next 40 trading quarters. If there is a supply deficit, essential demand must be prioritised according to the prioritisation procedure established by CREG.

The second set of measures addressing Colombia's growing natural gas supply deficit was issued in CREG through Resolutions CREG 102 021 and 102 022 of 2025.

Resolution CREG 102 021 eases the contracting of transportation capacity by:

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allowing that the duration and time intervals in the secondary market be agreed freely by the parties until the last standard negotiation quarter of gas year 2030, whereupon CREG regulatory terms will again apply. This harmonises with the terms applicable to the primary market; and

- extending the term where transportation capacity may be negotiated at any time in a standard negotiation quarter from 30 November 2025 to 31 August 2026.

Both these modifications result from the fact that the last two quarters of supply were insufficient to meet transportation purchase requests from agents.

Resolution 102 022 of 2025 expands the definition in Resolution 102 015 of excusable event from being exhaustive to now allowing the parties to include the types of events applied in the “LNG Sales and Purchase Agreements (SPAs)”. It also requires using such agreements for determining the supplier’s excusable event management and reporting duties and the affected party’s duties to prevent or mitigate a triggering action.

The third measure is that MME issued Resolution 40163 on 18 March 2026, which sets guidelines for thermal generators to offer imported gas in the secondary market if not needed to supply the power market, and for it to be transported. It also sets the terms for thermal generators to purchase imported liquefied petroleum gas, replacing gas sold in the secondary market. This resolution will apply until CREG issues a final regulation within six months.

Note also that MME is working on a draft decree to be put for discussion by market participants on 30 December 2025. It is aimed at ensuring the security and reliability of natural gas supply through increased transparency and market mechanisms (while also promoting biogas and biomethane by creating a regulatory framework to integrate them as key energy sources in Colombia).

An incidental marketing change would be a transitional price control mechanism if the available natural gas were less than 1.15 times the country's demand, which would trigger that:

- supply contracts that do not guarantee firmness could not then be priced higher than the average price of the same producer’s or trader’s or LNG trader’s firm contracts; and
- gas in the secondary market could not be traded above its original contracted value plus the 90-day fixed term deposit interest rate published by the Colombian central bank, plus 1%, looking to avoid speculation.

Additionally, the draft decree would materially modify the following definitions:

- "firm contract subject to conditions" would be when a market agent guarantees supply of a maximum quantity of natural gas or imported natural gas, or both, without interruptions, for a set period except for scheduled maintenance, the firmness thereof being conditioned to the producer having natural gas reserves or the natural gas import infrastructures being commissioned. This type of contract does not require physical backup; and
- "producer's committed production", which remains defined as natural gas daily quantities averaged monthly (measured in GBtu/d) that a producer commits for sale through firm supply contracts or that guarantee firmness, for each field or at a point

of entry to the SNT. This includes gas consumption by the producer's fully or partially owned refineries if it is committed for sale. The intention is to make more gas available to the market.

The same decree would introduce the following additional definitions for clarity in declaring the available imported quantities:

- "Quantities Imported with Supply Contracts – CIC: Average monthly daily quantities of natural gas, measured in GBTUD, that an imported gas trader has committed for sale through firm supply contracts or that guarantee firmness, for each source or at a point of entry to the SNT."
- "Import Potential of Natural Gas from a Given Source – PI: Quantities of natural gas, measured in GBTUD, regasified through a regasification infrastructure or transported through an international interconnection daily on a monthly average, at each source or placed at a point of entry to the SNT to meet the requirements of demand. These amounts are based on the nominal capacity of existing regasification infrastructures and international interconnections. The IP of a source corresponds to the sum of the CIC and the CIDV [Imported quantity available for sale]."

Finally, this draft MME decree establishes the enabling framework for biogas and biomethane, defining that through subsequent regulation, MME will determine the conditions for the injection, blending and use of biomethane in the national gas infrastructure and the progressive targets for biomethane participation in the fuel gas matrix.

As regards transportation, in 1999, CREG issued and has since amended the Unified Transportation Rules (RUT) for the SNT. RUT provides and regulates open access to the SNT, its efficient, economical and reliable operation, the development of gas supply and transportation markets, gas industry practices and terminology standards, and gas quality standards and specifications for transportation. The SNT currently comprises 7,750km, mainly composed of a horizontal trunk line that crosses most of the country's Caribbean seaboard and a vertical trunk line stretching inland from the eastern Caribbean coast to the Barrancabermeja station in east-central Colombia, where it turns west to traverse two Andes Mountain ranges to Cali at Yumbo, 103km from the central Pacific coast. This geographical and infrastructural composition imposes two transportation markets: the Caribbean coast and the Andes inland. Prices on the Caribbean coast market are higher than the national average price. Another major pipeline connects the Cusiana fields in mid-eastern Colombia westward over 405km with the trans-Andean trunk line at Vasconia in central Colombia.

Government take was to be increased through the 2022 tax reform by stating that royalties would not be deductible from taxable income on gas production. These fluctuate from 6% to 26% depending on monthly production volume at the well. Such non-deductibility was ruled unconstitutional in 2023 and confirmed to be so through three other decisions issued by the Colombian Constitutional Court up to 3 October 2024. The Colombian government attempted reviving this non deductibility though an economic emergency Decree 1474 issued in December 2025, which was declared unconstitutional by the Constitutional Court on 15 April 2026.

Law stated - 11 May 2026

Consumption

What percentage of the country's energy needs is met directly or indirectly with natural gas and LNG? What percentage of the country's natural gas needs is met through domestic production and imported production?

The Colombian 21,028 MW energy matrix by January 2026 is composed of hydropower 62.8%, thermal 29.6% and solar 7.6% with a fringe from other sources including wind.

About 22% of Colombia's energy needs were met with natural gas and LNG during 2025. The average demand at the end of October 2025 was 843.7GBtu/d, which is 28% lower than the 1,180GBtu/d delivered in October 2024. The daily average in 2025 was 862GBtu/d, which is 17% below the annual average for 2024 (1,041GBtu/d).

In 2025, industrial demand accounted for 24.9% of natural gas consumption, residential use for 18.2%, refineries for 14.4%, vehicular consumption for 6.3% and commercial users for 5.8%. The number of users increased since 2020 from 10,254 to 12,172 million in the fourth quarter of 2025.

Approximately 81.6% of consumed gas is domestically produced, including 8.2% from offshore wells, while 18.4% is imported LNG. The latter is mostly to supply four 2.071-megawatt thermal power plants located near to the LNG facility on the Caribbean coast.

Consumption by refineries in 2025 averaged 138.23GBtu/d, which is 16% of the country's consumption during standard operations.

Law stated - 11 May 2026

Government policy

What is the government's policy for the domestic natural gas sector and which bodies set it?

Natural gas sector policy is premised by constitutional precept and historic congressional laws. The constitutional principle is that the Colombian subsoil is owned by the nation as represented by the state. The right to produce natural gas is thus granted by the state to private and public companies through specific types of contracts.

Also on constitutional principle, market agents have the right to import natural gas, as under applicable regulation issued by the government pursuant to its constitutional duty of ensuring the efficient functioning of public services. This precept is also the basis for congress having enacted Law 142 of 1994 empowering the government and a sector commission to regulate the transportation and the wholesale and residential distribution of natural gas in Colombia.

Since taking office in August 2022, the government has announced that it would seek to amend or abrogate Law No. 142 of 1994. That will most possibly not happen by 7 August 2026 when the four-year presidential term ends. There is no bill in congress for that purpose. Thus, Law 142 of 1994 is the standing framework law for the natural gas residential service sector.

A caveat is that Colombia has upcoming presidential elections on 31 May 2026 with a possible second round on 21 June 2026. The polls show the candidate for the current president's political party to have a slight lead. This same party recently increased its Senate and House of Representatives' seats in the 8 March 2026 congressional elections, without, however, holding an absolute or controlling majority. Those developments could potentially convey that the current president's policy premises and perceptions carry over to the next administration, namely:

- tariff justice;
- universalising of service;
- regulation centred on the user;
- institutional strengthening and governance;
- focusing of subsidies; and
- community participation in the rendering of services.

A draft to amend Law 142 was worked on as early as February 2023, where the key elements reported were to refocus the law to protect the regulated user, be it through regulation issued by CREG or through the executive branch of government, whether directly or through delegation to the Superintendency of Residential Public (utilities) Services (SSPD). This would involve regulating tariffs, including the implementation of "vital minimum" tariffs to ensure the population's access to utilities. It would also include strengthening the SSPD's cost and tariffs monitoring capabilities, and its penalising faculties and powers, including intervening natural gas companies. Also salient in that draft is that public services networks built with state resources or with tariffs paid by users would be "collectively owned public goods and the [service] suppliers will be able to be remunerated for operation, replacement and maintenance, but not for the value of the network not invested by them".

Also relevant is that the Council of State (Colombia's highest administrative court) suspended Decree 227 of 2023 but has not yet handed down its final decision. This decree is where the President would temporarily assume regulatory functions delegated as per Law 142 of 1994 by the president's office to the regulatory commissions including CREG. The nullity suit argued that only Congress and not the President has the constitutional right to legislate on regulation of tariffs on utilities, such that this function could not have been delegated by the President. The Council of State's provisional decision preliminarily accepted this argument and later reiterated the suspension by having rejected the government's plea. This sort of suspension is premonitory but not a guarantee that the sued nullity will be granted

As for the status of Colombia's natural gas supply policies, on 15 October 2020, MME and its Mining and Energy Planning Unit (UPME) issued the Natural Gas Supply Plan through Resolution 40304 (the 2020 plan), which has implicitly been modified or qualified by following two official documents.

First, the current Colombian government's gas supply policy is stated in MME and ANH's 13 December 2022 joint and non-revised document, entitled "Balance of Hydrocarbons Contracts and Resources Available for the Just Energy Transition" (the Balance Document). It contains an assessment of proven, probable and possible gas reserves, plus estimates of additional gas as would be attained from contingent and prospective sources. In this approach, Colombia is argued to be capable of increasing natural gas reserves for up to 20 years of consumption by efficiently managing the existing balance of exploration and production (E&P) contracts. The premise is that their increased exploration efficiency and management will cause the country's reserve to meet projected consumption in the policy context of transitioning towards clean energies. The government has been consistent with this through 2023–2026 while considering gas importation options.

In that context, the Balance Document qualified or changed the 2020 Plan by the following policies:

- Improving recovery factors in production only under existing contracts (CREG issued regulatory incentives for exploration in those contracts).
- Advancing offshore E&P contracts also targeted by the Balance Document, but excluding any new offshore contracts.
- Fracking, which is recommended in the 2020 Plan, is not mentioned in the Balance Document. Three anti-fracking bills have been submitted to Congress during the current government the latest of which was in July 2025, but the congressional procedure will likely not be completed within the required terms. Moreover, the "integral research pilot projects", which were judicially allowed to determine the environmental viability of fracking, were suspended by Ecopetrol and then terminated by the contractor in 2023.
- An LNG 400mcf/d importation infrastructure on the Pacific coast for which two unsuccessful auctions were carried out. It is not clear whether a third one will be convoked.
- The six transportation projects embedded in SNT recommended in the 2020 Plan, which were supported by compensatory specific revenue flows (CREG Resolutions 502 061 through 064 of 2024), are still being executed with varying levels of completion. This includes the bidirectionality of the Caribbean coast and eastern Andean in land trunk lines and their connection at Ballena, most of which have already been attained. The other four projects' statuses range from being 80% completed (Mariquita-Gualanday capacity expansion), to awaiting a construction date (the Pacific coast Jamundí branch capacity increase).

Second, on 26 June 2024, UPME issued its Technical Study for the Adoption of the 2023–2038 National Natural Gas Supply Plan (the Technical Study), whose Recommendations Scenario listed new infrastructure projects meant "to guarantee the supply and reliability of the natural gas sector", namely:

- constructing a gas pipeline to enable transportation through an alternative route to the existing trunk line that connects the eastern Caribbean coast to central Colombia. This alternative route was to be the Jobo-Medellín by gas producer CANACOL. The project has since been cancelled due to alleged reasons of security and gas market dynamics;
- constructing a pipeline to connect the eastern city of Cúcuta on the Venezuelan border to the SNT's Ballena–Barrancabermeja trunk line. A mid-term supply shortage for Cúcuta is foreseen by 2030. This is still being considered as an option to gas being imported from Venezuela;
- have a connecting pipeline from the Bogotá region to the SNT by optimising existing infrastructure with compression stations and loops in the midterm. This would be alternative supply to the capital city's current SNT connection to declining fields on

the eastern plains (Cusiana) and to the offshore Chuchupa wells. This complements the Mariquita–Gualanday capacity expansion noted above;

- reactivating the 500mcf/d PDVSA pipeline from Venezuela to the Ballena hub. On 13 March 2026, PDVSA said that it would rather rescind the existing contract because its terms are uneconomical considering the involved investment. Therefore, this is an unlikely though much publicised project;
- implementing LNG importation infrastructure on the Pacific coast, which for the third auction is yet to convoked by UPME. This could be redundant to another LNG project in the same region now advanced by Ecopetrol and a co-contractor to deliver 60mcf/d in 2026 increasing this to 120mcf/d at a later date; and
- starting in the fourth quarter of 2031, importation to the SNT of 533mcf/d from the current LNG regasification facility on the Caribbean coast at Cartagena when the standing supply commitments with thermal generators will then expire. Its operational capacity is now at 475mcf/d and the import trader has implemented delivery processes to third-party buyers.

Law stated - 11 May 2026

Regulatory authorities
Which authorities make regulatory policies and decisions in respect of the production, transmission, distribution and supply of natural gas?

The governmental bodies charged with managing and regulating the sector are:

- The Ministry of Mines and Energy (MME), which is responsible for adopting the government's policies on the exploration, production, transportation, processing and distribution of hydrocarbons, as well as for setting policies for developing the mining and power sectors. MME determines, inter alia, the order of priority for supplying natural gas to the various sectors and, in extraordinary circumstances, it can mandate supply restrictions.
- The National Hydrocarbons Agency (ANH), which is an administrative body created in 2003 to manage Colombia's hydrocarbon reserves and resources and implement public policies regarding oil and gas sustainable exploration and exploitation, for which it implements MME's policies on hydrocarbons area awarding and contracting.
- MME's Mining and Energy Planning Unit (UPME), which is responsible for developing and updating the National Energy Plan and the National Electric Reference Expansion Plans. UPME is also responsible for forecasting the overall energy requirements of Colombia's planning and for developing ways and means to satisfy its energy requirements. In that context it issues the National Natural Gas Supply Plan and identifies and awards natural gas sector infrastructure development projects.
- The Energy and Gas Regulatory Commission (CREG), which is a special administrative unit of MME to which the President of Colombia's constitutional function has been delegated for setting general policy to regulate, administer and control the efficient rendering of residential public services (utilities). Accordingly, CREG issues resolutions on the rendering of fuel gas service. It also has the faculty of setting tariff methodologies, free competition and anti-monopoly practices,

service quality and continuity standards, access to and use of the transportation and distribution grids, purchase and sale contractual modes between market agents, and market management operations.

CREG is composed of the following members:

- MME, who heads CREG;
- the Minister of Finance and Public Credit;
- the Director of the National Planning Department;
- six independent technical expert commissioners, each appointed by the country's president for a four-year period; and
- SSPD, which is the only non-voting commissioner and is the compliance oversight authority with powers to sanction and intervene services.

Decisions require the favourable vote of at least five members including at least four expert commissioners.

Law stated - 11 May 2026

REGULATION OF NATURAL GAS PRODUCTION

Ownership and organisation

What is the ownership and organisational structure for production of natural gas (other than LNG)? How does the government derive value from natural gas production?

Production from exploration and production (E&P) contracts awarded in the National Hydrocarbons Agency (ANH)'s 2021 auction is split into the producer's take and the government's take by way of:

- The "X" percentage. This is a royalty on production agreed by ANH with each E&P contract awardee over and above minimum percentages drawn from a regulatorily set sliding scale, where the rate increases from 6% for low production fields to 25% for fields whose average daily production exceeds the natural gas equivalent of 600,000 barrels of oil (about 3.48 billion cubic feet). Most fields qualify for either 8% on 5,000 to 125,000 barrels or 20% on 125,000 to 600,000 barrels, plus the percentage points agreed with ANH through competitive bidding. The government intended to increase that take through the 2022 tax reform by stating that royalties would not be deductible from taxable income on gas production. This was ruled unconstitutional in 2023 and confirmed to be so through three other decisions issued by the Colombian Constitutional Court up to 3 October 2024. The Colombian government attempted to revive it through economic emergency Decree 1474 issued in December 2025, which was provisionally suspended by the Constitutional Court on 29 January 2026. The same grounds for unconstitutionality that were applied in 2023 apply here (thus it is unlikely that this decree will become effective).
- Annually adjusted economic right rates for E&P contracts using Rates and Base Price Po, as measured by the annual change in the United States Producer Price Index of America "Final Demand", WPUFD4 (see ANH Resolution 0325 dated 26 May 2025),

as applicable to the surface fee for subsoil use and depletion of the resource, at the time of writing at the following values until 30 April 2026. This will be updated yearly by ANH (note that higher fees apply for exploration and evaluation periods without production depending on the onshore block's size and time elapsed, as well as on offshore blocks) using:

  - £1.17 per hectare for continental areas (including non-production exploration and evaluation periods);
  - £0.75 per hectare for offshore areas at water depths of less than or equal to 1,000 metres; and
  - £0.16 per hectare for offshore areas at water depths of more than 1,000 metres.

- Contributions for training, institutional strengthening and technology transfer (see ANH Resolution 325 dated 26 May 2025).
- High price participation fees (see ANH Resolution 325 dated 26 May 2025).
- Mandatory social investments for 1% of the total worth of the annual:
  - minimum and supplementary exploration programme; and
  - operation programme for all producing commercial fields in the production area.
- Community Investment Programmes (PBCs) offers in each bidding.
- Technical evaluation agreement (TEA) or E&P contract signature bonus.

The 2022 tax reform revised the Colombian peso national carbon tax per cubic metre of natural gas, now regulated at 44.73 pesos per cubic metre in 2026. It is adjusted on 1 February of every subsequent year applying the Colombian Consumer Price Index as published by the National Administrative Department of Statistics for the previous year, plus 1% with a cap at 3 tax value units (UVTs as per their acronym in Spanish equal to COP$52,374 in 2026). This tax applies only to natural gas production destined to petrochemical plants and refineries.

That same 2022 tax reform may also convey an increased income tax burden on all corporate taxpayers including foreign branches and subsidiaries of foreign corporations if the 35% corporate income tax rate would render a tax less than 15% of "refined profit". That refinement is computed on the taxpayer's accounting profit and thus does not allow for the deduction of any and all costs, whether these be domestic or incurred offshore and imputed by a foreign parent to its Colombian operation. This manner of computing income tax is the refined taxation rate (TTD). It is criticised for not being technically conceived as it can cause double taxation because it has value components (such as currency fluctuations) that may increase the worth of accounting income on which the TTD 15% applies, but will then materialise in a later year as fiscal income to be again taxed at the 35% corporate tax rate. This is being challenged before the Colombian constitutional court for violation of the principles of justice, horizontal equity and tax equality.

Finally, the natural gas field's assets will revert to the Colombian state when the E&P contract terminates for any cause. At that point, the contractor is obliged to deliver producing wells in perfect condition, as well as to deliver buildings and other field installations in good working conditions. Rights of way and other permits will also be effectively delivered. This is all carried out without compensation.

Law stated - 11 May 2026

Regulatory framework

Describe the statutory and regulatory framework and any relevant authorisations applicable to natural gas exploration and production.

Even though no new areas conveying E&P agreements have been awarded since 2021 nor are expected to be so during the presidential administration ending on 7 August 2026, the regulatory structure for producing set by the National Hydrocarbon's Agency (ANH)'s Agreement 3 of 25 July 2022 and Agreement 7 of 5 August 2022. These agreements contain specific rules called the Area Nomination Open Process (PANA). PANA regulates contracting of exploration, evaluation and exploitation of hydrocarbons, and the selection of contractors. Previously existing contracts remain governed by the Area Assignment Permanent Process (PPAA), as well as by prior regulation applicable to each contract when executed. However, ANH Agreement 3 of 2022 allows contractors under any prior regulations (including the PPAA) to agree with ANH on using the ICC international arbitration clause applied for the 2021 auction round.

Under PANA, a bidder must meet certain contractual standards to qualify for each of the economic-financial, technical-operational, environmental, corporate social responsibility and legal eligibility capacities. ANH allows contractual capacities to be accredited through the interested party's affiliates, in which case the affiliate must assume joint and several liability for the fulfilment of obligations and commitments under the awarded contract. For this purpose, the affiliate must issue a joint and several debtor guarantee, accompanied by a legal opinion prepared applying terms and formats required by ANH to be used by an external lawyer or an independent law firm. The affiliate may alternatively deliver a Certification on Operations Insurance in Colombia, reflecting the existence of one or more insurance policies covering the risks of, and obligations derived from, operating in Colombian territory. This insurance is different from that taken by the awardee for the contract's performance itself. Furthermore, evidence must be submitted that the affiliate's underwriter has an investment grade credit rating for long-term debt given by Standard & Poor's, Moody's, Fitch Ratings, AM Best or Weiss Ratings.

On completion of the authorisation procedure, the interested party may participate in contractor selection and area-nomination processes conducted by ANH. This selection may be through competitive or direct processes as decided by ANH. Most processes have been competitive. Parties who have previously and successfully registered with ANH as being contractually capable are allowed to submit bids in competitive processes. These can be:

- open, in the sense that a bid by any authorised party for an available area would be acceptable at any time of the year. This type of bid must be published by ANH, thus allowing other parties to submit counteroffers at a hearing. If a counteroffer exceeds the original bid, its bidder will be preferred for award if it rebids matching the counteroffer; or
- special, when ANH calls for bids according to a set schedule, whose operation programme for all may be open or closed depending on whether ANH invites all and

any registered contractors, or a limited number of registered parties considering a given area's special characteristics. An interested party's offer will be valid if it equals or exceeds the minimum bid values required by the ANH for:

- scoring the exploratory programme in the case of a technical evaluation contract (CET, formerly TEA) or for scoring the carbon management offer and the economic value of exclusivity (VEE) in the case of hydrocarbons E&P contracts; and
- the "X percentage", which is ANH's participation in production. CET contractors must develop an exploratory programme that includes both the minimum programme required by the ANH and an additional programme offered by the interested party. Such added value is a factor weighted into the evaluation and qualification formula for awarding a CET.

For E&P contracts, the ANH will compare the offers using a weighted scoring formula relative to the involved factors, where carbon management carries the most weight over each of the other factors:

- carbon management, for which PANA requires a commitment to reduce or offset carbon emissions for the production period at the rate of no less than 25kg per barrel of oil (approximately 5,700 ft^3 of natural gas), to be evidenced by emission reduction certifications or by offsetting carbon credits;
- the worth of exploration investment offered and accepted is called VEE;
- the percentage of share in production (X%);
- offers of investment in community benefit programmes (PBCs);
- offers for contracting goods and services with local, regional and national content;
- the contract signature bonus as an eligibility requisite consisting of the payment made to the ANH as offered in the bidding, prior to the awarded contract being executed;
- any other remuneration in favour of the ANH or for the benefit of Colombia;
- the minimum and additional exploration programmes;
- the percentage of participation in shared production contracts (this only applies when a contract is extended approaching expiration, as the field would otherwise revert to the Colombian nation); and
- offers for PBCs in addition to mandatory social investments. Both are investments in programmes for the improvement of quality and living conditions of inhabitants in the areas influenced by the given contract's performance. These investments must account for the priorities and needs stated by communities in the area. The mandatory investments must be for at least 1% of the total worth of the annual:
  - minimum and supplementary exploration programme; and
  - operation programme for all producing commercial fields in the production area.

ANH Agreement 3 of 2022 was amended by ANH's Agreements 2 of 11 January 2023 and 3 of 30 April 2024. Conforming to the current administration's policy against having new E&P contracts, these amendments:

- abrogate provisions in articles 17 and 18 permitting the direct assignment of areas to an associated operator who has terminated production or reverted the field to Colombia; and
- insert a new provision that allows ANH to contract the operation and management of areas either due to the production period having ended or to reversion of areas to the Colombia and, generally, where managing "the Nation's" assets would be necessary for production in existing deposits.

Further relevant for authorisation is that gas producers that are wholesale market retailers must be registered with the Public Residential Services (utilities) Superintendence (SSPD) and Energy and Natural Gas Regulatory Commission (CREG), provide reports periodically to the SSPD related to transactional and operational information, and deliver financial statements. Additionally, Law No. 142 of 1994 requires producers to hire an external auditor charged with delivering an annual report to the SSPD on the consistency of a producer's management with legal, technical, financial and accounting regulatory requirements.

Hydrocarbons E&P is also subject to environmental permitting issued by the National Environmental Licences Authority (ANLA). The ANLA's licence covers the performance of each E&P activity and works, for which the contractor must submit an environmental impact study including information on the project, the place where it is to be developed, the natural resources to be used, information on impacts and risks, and a contingency plan previewing remedies in the case of spills and fires, as well as damage compensation plans. If the ANLA's licence is not global, the contractor must obtain environmental permits for the use of or pointed impact on natural resources, such as for surface water catchment, wastewater discharging, forest depletion and atmospheric emissions. Another requisite for the environmental licence's issuance is that the project company must have previously made a socioeconomic characterisation of the project's influence area together with a follow-up monitoring programme in that respect.

Finally, the project company is required to inform the relevant communities about the project's scope and impact, and the measures proposed for impact management thereof. The Ministry of the Interior must also certify that the project company has complied with prior consultations with neighbouring black and indigenous communities. The terms for this consultation are set by the Ministry's Prior Consultation National Authority. This may include the quantification of direct impacts and ameliorating or compensatory measures as agreed with the involved ethnic communities.

Law stated - 11 May 2026

Unconventional gas production

Are there different rules for, or any restrictions on, unconventional natural gas production (including fracking)?

To date, six anti-fracking bills have been filed with Congress, starting in 2022. They have all been for expressly prohibiting the exploration and production of hydrocarbons from unconventional deposits (fracking), as well as the subscription, addition or granting of related contracts, concessions, licences and environmental permits. The sixth bill (PL 053 Chamber of Representatives/PL 294 Senate) was filed on 22 July 2025 and has been approved by the relevant commissions and is now being debated in both chambers' floors during the 2026 sessions ending on 20 June under an urgency prompting filed by the President of Colombia.

In practice, fracking activity has ceased considering the current government's hydrocarbons policies. Ecopetrol suspended and then agreed in early 2023 with Exxon Mobil to terminate their agreements for evaluating the environmental impact of fracking techniques in two sites. In the same vein, the Ministry of Mines and Energy has wholly abrogated Resolutions 180742 of 2012 and 90341 of 2014, which contained technical and procedural regulations regarding the integrity of wells, hydraulic stimulation, production water injection, fluids return and other technical matters associated with the exploration and exploitation of unconventional wells.

There could, however, be a revival of arguments for fracking as industry experts are insisting that Colombia has substantial exploratory potential using "fracking 4.0" whose environmental impact is substantially reduced due to its alternative fuel techniques. There is persistent reference to this in industry publications and awareness among government officials and congress members.

Law stated - 11 May 2026

Required security and guarantees

Are participants required to provide security or any guarantees to be issued with a licence to explore for or to store gas?

The PANA used by ANH under its Agreements 3 and 7 of 2022 requires that the potential proponents be previously registered as enabled to contract with ANH based on its economic, financial, technical, operational, environmental and legal documentary requirements. A contractor qualified to bid is required to deliver a bid bond with a six-month validity extendable at ANH's request. It covers all obligations derived from bidding and being awarded an E&P contract. The insurer must be either an acceptable Colombian insurer or a foreign or national financial institution.

If the contractor's indicators are insufficient for bidding, its parent company indicators may be used in support. This entails that the parent or an affiliate must deliver a joint and several guarantee fracking for the contractor's performance of its obligations and commitments according to the ANH's specific rules for each bid. This guarantee may be delivered in the form of:

- a Certification on Operations Insurance in Colombia reflecting the existence of one or more insurance policies (other than those required for performance under the E&P or CET contract), covering risks and obligations arising from the contract and from operations in Colombian territory. The certification will also be conditional on the insurers having investment-grade credit ratings for long-term debt granted by Standard & Poor's, Moody's, Fitch Ratings, AM Best or Weiss Ratings); or
- a joint and several debtor guarantee (tantamount to a corporate guarantee) supported on a legal opinion issued by an external lawyer or an independent law firm in the terms and formats required by ANH.

A winner must, on award, deliver a performance guarantee for all obligations under the contract, replacing the initial bidding bond covering, inter alia, the investment value proposed as VEE, and as per the contract deliver:

- a guarantee covering the contractor's labour, social security and occupational health obligations under the E&P contract, with validity for the contract's term plus three years;
- tort liability for damage to third parties caused by the contractor's, its employees' or its dependants' activities; and
- an abandonment fund guarantee for the value of the abandonment and environmental restitution activities to be performed at the end of the E&P contract (this is calculated with a specific formula).

Law stated - 11 May 2026

REGULATION OF NATURAL GAS PIPELINE TRANSPORTATION AND STORAGE

Ownership and infrastructure

Describe in general the ownership of natural gas pipeline transportation, and storage infrastructure.

The Colombian natural gas pipeline grid is organised as the National Transportation System (SNT) as per the Ministry of Mines and Energy (MME)'s framework regulation and its derived regulation issued by the Energy and Natural Gas Regulatory Commission (CREG).

Law No. 142 of 1994 defines the transportation of natural gas as a public residential (utility) service to be rendered according to government regulations. Nonetheless, there is no limitation on the source of ownership other than the applicability of regulations on legal contractual enablement and anticorruption. Pipelines in Colombia may be directly or indirectly owned by either national or foreign private investors or by governmental enterprises through special purpose entities qualified as utility services stock-holding corporations (each an "ESP"). Exceptionally, as was the case for the Ballena-Barrancabermeja Pipeline BOMT project, the project company is not required to be an ESP if it is not a market agent but is subject to all sector regulations where it qualifies as an activity complementary to gas transportation.

Before commencing activities, transporters must be registered with the Public Residential Services (utilities) Superintendence (SSPD). While operating, they must periodically provide reports related to transactional and operational information, as well as financial statements to the SSPD. Additionally, Law No. 142 of 1994 requires transporters to hire an external auditor charged with delivering an annual report to the SSPD as to the consistency of the transporter's management with applicable legal, technical financial and accounting regulations.

Storage services are not the subject of regulation on large-scale storage. Other than for LNG on the Caribbean coast, there is currently no storage facility in Colombia that needs regulation on pricing. However, further storage-relates regulation may be needed as new LNG facilities materialise in Colombia.

CREG Resolutions 185 of 2020 and 175 of 2021 on parking gas enable a transporter to negotiate with a supplier a certain volume of natural gas that can be stored (line packed) in the transportation system for a period and at a price agreed between the parties, provided this would not pose any risk to the national grid's operation.

In any case, the regulation does not forbid either transporters or third parties from investing in storage facilities, as this service may be rendered apart from that of transportation proper. However, if the party contracting the storage is a transporter, it may not own the gas save for the quantity required to operate the storage system.

Law stated - 11 May 2026

Regulatory framework

Describe the statutory and regulatory framework and any relevant authorisations applicable to the construction, ownership, operation and interconnection of natural gas transportation pipelines, and storage.

Ownership may be held through private or mixed capital companies with the special purpose of building (as applicable) and operating a natural gas transportation pipeline or an imported gas storage and supply infrastructure. That purpose is constitutionally defined to be a public service, further qualified in the law as being a residential public (utility) service. As such, this a service subject to public interest law and regulations issued by the Ministry of Mines and Energy (MME) and CREG, to authorisations and oversight by MME, CREG and the SSPD, and by environmental authorities (the National Environmental Licences Authority ANLA) and autonomous regional corporations).

Building a pipeline requires prior environmental licensing by the ANLA, and the construction process must meet all specific permitting needs, such as river and road crossings and rights of way obtained by eminent domain. This encompasses local administrative and regional environmental authorities, landowners and possessors, expeditious indemnity dispute resolution before municipal civil courts, and performance and compensation agreements with affected communities. Furthermore, where Indigenous or Black communities would be affected, a prior consultation process is required under the oversight of the Ministry of Interior.

Operating a pipeline is subject to CREG Resolution 071 of 1999 (as amended) containing the natural gas Unified Transportation Rules (RUT) and is governed by the principles of open and non-discriminatory access and quality and security conditions set forth in the RUT and other regulations.

Pipeline operation and maintenance (O&M) is subject to rules in the RUT and other regulations issued by CREG and MME. Additionally, the RUT requires that each transporter issue an O&M manual for its pipeline. SSPD oversees the observance of these rules, which must be informed periodically by the transporter according to a format. The transporter is obligated to maintain the facility in a technically balanced condition.

Law stated - 11 May 2026

Land rights

How does a company obtain the land rights to construct a natural gas transportation or storage facility? Is the method for obtaining land rights to construct natural gas distribution network infrastructure broadly similar?

Law No. 1274 of 2009 reiterates the long-standing legal figure of a "petroleum transit and permanent occupation right of way", a form of eminent domain applicable to natural gas pipelines. This allows the transporter or distributor to occupy land within a regulated right of way or easement width to build and maintain a pipeline for as long as the pipeline is operative. Indemnifying owners or possessors for damages is mandatory but does not affect establishing the right of way. This is a matter of land encumbrance (servitude) for which damage caused is indemnified, not a matter of expropriation for which land value indemnification would be due.

Easements apply to the layout as approved by MME. The transporter's land negotiator will agree with the owner or possessor on the value of damage caused by the pipeline and its easement on the property. A right-of-way acknowledgement agreement with the attached minutes of damages recognition should be formally executed by the parties on the ground. If this fails, the right of way may be issued by the competent administrative authority or, at the transporter's choice, by a municipal judge before whom the value of damages indemnity will also be set according to an expert appraisal. This does not interrupt the construction works.

It should be noted that attaining the right of way is subject to all applicable environmental licensing being previously in place.

Law stated - 11 May 2026

Access

How is access to the natural gas transportation system and storage facilities arranged? How are tolls and tariffs established?

Governed by the RUT's principles, transporters must offer open and non-discriminatory access to natural gas market agents and final users. This access is however subject to applicable quality and security conditions set in the RUT and other CREG regulations being observed. The connection contract must stipulate which party is responsible for the construction and which party owns the connection itself. If construction is to be by the transporter, a connection charge will apply, reflecting construction costs and the supply of metering and flow control equipment. If there is no agreement on the above within a month of formally initiating negotiations, CREG may directly impose the technical and economic conditions applicable to the connection.

The connection owner is responsible for purchasing the land and rights of way, and for obtaining all necessary permits. The cost incurred may also be reflected in the connection charge if the connection is owned by the transporter. The owner is also responsible for operating and maintaining the connection unless the parties agree otherwise.

The entry and exit points must be built, owned and operated by the transporter except where it refuses to do so for technical reasons.

Transporters may deny direct access to the transportation system only if the relevant local distributor fails to meet flow, pressure gas quality or security technical service standards.

Law stated - 11 May 2026

Interconnection and expansion

Can customers, other natural gas suppliers or an authority require a pipeline or storage facilities owner or operator to expand its facilities to accommodate new customers? If so, who bears the costs of interconnection or expansion?

The regulation distinguishes between expansion required in existing pipelines (eg, loops, compressor stations and bidirectional flow) and new expansion.

If projects put by MME's Planning Unit (UPME) in its gas supply plans involve the expansion of existing pipelines, each given transporter has priority to conduct the project on its pipeline at the regulated tariff determined by CREG Resolution 175 of 2021 as amended successively by CREG Resolutions 102-001 of 2012, 102-005 of 2022, 02-006 of 2022, 102-010 of 2022, 102-008 of 2024, 102-012 of 2024 and 102-016 of 2025.

If the transporter is unwilling to make the investment required in the existing pipeline or a new expansion embedded in its infrastructure, UPME will organise a public auction and award it to the lowest-priced offeror. The bids must propose an expected annual income (IAE), which includes the total capital expenditure and operating expenses for the duration of the project as per CREG Resolution 102-008 of 2022 as modified by CREG Resolutions 102-3 of 2023 and 102 012 of 2024. CREG Resolution 102-016 of 2025 enables UPME to issue detailed technical procedural rules, which it did through External Circular 104 of 2025 to implement the IAE-based auction mechanism established in the preceding resolutions.

Regarding trunk line interconnections or trunk lines with distribution lines, the regulation charges the petitioning transporter with building, operating and maintaining the interconnection station. The interconnection point must have metering, quality assessment and flow-control equipment to determine the transfer of custody. If there is no agreement on the above within a month of having formally initiated negotiations, CREG may, on request by either party, directly impose the technical and economic conditions applicable to the interconnection.

Alternatively, transporters within SNT may want to expand capacity with a project not included in the National Gas Supply Plan. In this case, project income is not determined through the IAE system. Rather, as per CREG Resolution 175 of 2021, the transporter reports to CREG the projected investments and the date of commissioning of the assets. CREG then uses this to assess the regulated tariff with which to remunerate capital expenditure and operating expenses at cost-effective values of the new assets throughout an assumed useful life. To this end, CREG shall also compare these with the effective costs of other comparable assets. Although Resolutions 102-005 and 102-006 of 2022 updated certain tariff methodology aspects, they do not alter the fundamental distinction of that non-plan expansions are remunerated via cost-based regulated tariffs rather than the IAE auction mechanism. These projects are meant to meet new demand during a term equal to the infrastructure asset’s useful life, which is assumed to be 20 years from the date of commissioning. That is the term during which the transporter should recover the investment.

Finally, projects not included in the SNT may be undertaken by individual sector agents under the "open season" system as per CREG Resolution 155 of 2017. This system is meant for new facilities that are not a part of the Natural Gas Supply Plan (ie, they are neither capacity expansions – loops and compression stations – nor exclusive use pipelines). The economics for these projects rely not on the regulated tariff but on the expected market demand. They are structured projects where all supply and demand terms and rates are arranged by the transporter with producers, retailers and non-regulated users. However, commercial operators that participate in the open season representing regulated users cannot agree on a rate that exceeds the regulated tariff.

Law stated - 11 May 2026

Processing
Describe any statutory and regulatory requirements applicable to the processing of natural gas to extract liquids and to prepare it for pipeline transportation.

Section 6.3 of the RUT contained in CREG Resolution 71 of 1999 as amended by article 2 of Resolution 50 of 2018 regulates the quality of natural gas at the entry and exit points. There is no specific provision on the extraction of liquids as such; however, gas at either point must not contain liquids (hydrocarbons, water or other contaminants in a liquid state). The dew avoidance temperature at any pressure on the gas is not to exceed 450 Fahrenheit, according to the ASTM D-1142 or more accurate standards. The transporter may not receive non-compliant gas until an expert assessment certifies compliance. The transporter must have adequate measurement equipment both at entry and exit points and apply measurement methods agreed upon by the parties.

Law stated - 11 May 2026

Contracts
Describe the contractual regime for transportation and storage.

Under CREG Resolution 185 of 2020, the Colombian natural gas transportation wholesale market is composed of primary and secondary markets. The primary market is where transporters sell capacity to producers, LNG importers, retailers or unregulated users (ie, large-scale customers). The secondary market is where retailers and unregulated users sell unused capacity to each other. Contracts in both markets are directly negotiated by the parties either for a firm and fixed capacity or for transportation with capacity interruption. These agreements are governed by Colombian civil and commercial law as per the Colombian residential public services (utilities) statute (Law No. 142 of 1994). All contractual structures used in the sector are set by regulation, such as quarterly fixed and firm contracts, or fixed and firm conditional, or purchase option or contingency transportation contracts, as would be applicable depending on the market level and agents involved. Nonetheless, to have stable public utility services, Resolution 185 of 2020 requires that contracts at least:

- include a *force majeure* and extraneous causes clause;

- a definition of liability exonerating events (eg, interruption for programmed maintenance or works); and
- a detailed definitions and procedures clause for non-compliance events.

Prices are set through bilateral negotiation between transporters and retailers or large-scale users under a contract carriage scheme, with a price cap set under the regulation to remunerate capital expenditure and operating expenses per each natural gas pipeline segment.

As per CREG Resolution 185 of 2020, the Natural Gas Market Manager must prepare a balance of available and demanded gas transportation capacities for all quarters in the next 10 years. This is based on information delivered by the market agents on gas transportation demand and capacity committed under existing contracts registered with the Natural Gas Market Manager. Even though these contracts are protected by confidentiality, the Natural Gas Market Manager is allowed to aggregate information for the purpose of preparing and publicising such a projection. If the projected supply exceeds demand in that 10-year horizon, parties are free to negotiate contracts for any agreed duration, provided their initiation and the termination dates coincide with those of calendar quarters of the relevant year. This is to avoid market cornering. However, if the demand under quarterly fixed and firm contracts exceeds supply, CREG Resolution 001 of 2021 establishes a procedure to allocate the capacity among agents.

Note that CREG Resolution 185 of 2020 has been amended in material respects by:

- CREG Resolution126 of 2021 setting terms for primary market purchasers of transportation capacity and for parking under exceptional circumstances; and
- CREG Resolution102-10 of 2024, which for periods of low hydrology:
    - exempts producers, traders and importers from applying the regulation's marketing mechanisms to the sale of gas in excess of firm energy obligations, provided that "essential demand" has previously been met;
    - allows transporters to market their primary available capacity at any time under the duration of conditions defined by themselves; and
    - requires that primary available transportation capacity contracts be signed and registered with the natural gas market manager for service on or after the last quarter of gas year 2030 to again contain a contractual conditions regulatory adjustment clause to the provisions determined by CREG.

Law stated - 11 May 2026

REGULATION OF NATURAL GAS DISTRIBUTION

Ownership
Describe in general the ownership of natural gas distribution networks.

There is no restriction on the origin or legal nature of the owner of a gas distribution facility. Gas distributors are corporate vehicles established in Colombia as utility services stock-holding corporations (a public services enterprise (ESP)). A retailer classifies as a distributor-retailer if it has a pipeline network, or only as a retailer if it does not. In either case both are required to be an ESP and are subject to gas-sector regulation.

Law stated - 11 May 2026

Regulatory framework

Describe the statutory and regulatory structure and authorisations required to operate a distribution network. To what extent are gas distribution utilities subject to public service obligations?

The first requirement is the incorporation of a stock-holding corporation with the purpose of distributing natural gas. This entity must be an ESP. This is because the activity per se- is statutorily defined as a utility service subject to all public service obligations set out in Colombian regulation.

An ESP must also be registered before the Public Residential Services (utilities) Superintendence (SSPD), to whom periodical reports related to transactional and operational information, as well as financial statements, must be submitted. Additionally, Law No. 142 of 1994 requires distributors to hire an external auditor who will present an annual report to the SSPD with conclusions about management consistency with legal, technical, financial and accounting requirements. The SSPD is entitled to take possession either for the temporary administration or liquidation of a utility in case of jeopardy to the proper rendering of a public service due to defective performance or financial distress.

The regulatory structure for natural gas distribution is laid out in the following Energy and Gas Regulatory Commission's (CREG) resolutions:

- Resolution 67 of 1995 as amended, which establishes Technical and operational rules in the Fuel Gas Distribution Code by Networks.
- Resolution 57 of 1996 amended, which incorporates the above cited with amendments and establishes the economic, legal regulatory framework for the public service of fuel gas by network.
- Resolution 137 of 2013 as amended, which defines general tariff formula applicable to regulated users connected to distribution networks.
- Resolution 202 of 2013 as modified, which establishes the methodology for remuneration of the distribution activity and for approval for use charges.
- Resolution 102 003 of 2022 regulates marketing including the approval of the fixed component of the cost of marketing associated with distribution.

Law stated - 11 May 2026

Access and pricing

How is access to the natural gas distribution grid organised? Describe any regulation of the prices for distribution services. In which circumstances can a rate or term of service be changed?

The distribution system is an interconnected and interdependent network in which the activities of a participant agent can affect the rates of other agents. Thus, the principal objective of this distribution system is to maintain the concerned distributors and other involved agents within the same common interest under conditions set out, inter alia, by the Third-Party Access Contract (ATR) (CREG Resolution 057 of 1996 as amended) and the Distribution Code (contained in CREG Resolution 67 of 1995 as amended).

This occurs in the context of a regulated price freedom system, where CREG sets the rules and formulas for calculating tariffs that the distributors apply to determine the final rate while ensuring their efficiency, financial viability and fair pricing.

CREG requires distributors to connect any new end user unless there are technical reasons not to do so or if the site is in a high-risk area, or if the connection would be uneconomic as assessed according to normal commercial standards. Any refusal to connect may be appealed by an end user before the SSPD. CREG further requires the end user to build its access into the internal network and for access to be certified for technical compliance and security by an independent certification organism. The connection charge must be paid by the end user to the distributor, who shall thereafter have 30 business days to make the connection.

Retailers, transporters, other distributors or non-regulated users may request that the distributor enter a third-party access agreement regarding which party is to make the investment for connecting to the distribution system, the technical conditions, metering and fees according to regulated tariffs and duration. A basic condition for accessing the distribution network is that the distributor deliver a certificate of available transportation capacity and make a connection costs offer to the interested party. This is a prerequisite for the distributor to offer an ATR to a transporter, another distributor, a retailer or a non-regulated user. The distributor must refrain from offering access if the connection counters any technical or environmental regulation. If the parties do not reach an agreement after four months of negotiation, CREG shall rule on the conflict and may, on request by either party, directly impose the technical and economic conditions applicable to the connection.

CREG regulates the procedure for a new source of natural gas to be directly connected to a distribution system pipeline, on condition that the source not be already connected to the national grid, and that its production capacity be less than 30mcf/d. The distributor may not refuse connection unless there is a technical reason to do so or if it is proven uneconomical.

Law stated - 11 May 2026

System/service expansion and limitation

May the regulator require a distributor to expand its system to accommodate new customers? May the regulator require the distributor to limit service to existing customers so that new customers can be served?

The distributor has the right to plan the expansion of its network without the regulator having authority to require an expansion. The Colombian government resorts to subsidies as investment incentives for distribution companies to expand the system. However, the Distribution Code issued by CREG Resolution 67 of 1995, as amended, establishes that the distributor must submit its expansion plans to CREG, including alternatives with their expected investments to cover new geographical areas. These plans must account for demand projections made between CREG and the Ministry of Mines and Energy's Planning Unit (UPME). These plans must also be compliant with technical and security requisites applicable under the standing regulation. Additionally, minimum cost options must be presented (including investments and operation maintenance costs), and they must minimise losses for the system while permitting future expansion. The most convenient option among those presented by the distributor will then be selected by CREG on its judgement and in consultation with the UPME. CREG will then issue tariff authorisations for the preferred alternatives and the distributor may or not conduct the selected expansion at its discretion.

Law stated - 11 May 2026

Contracts
Describe the contractual regime in relation to natural gas distribution.

The contractual regime differs depending on whether the distributor is to serve a non-regulated user (ie, a large-scale user) or a regulated user. In the former case, the free-market regime applies subject to regulation pertaining to the gas transportation market depending on whether the distributor is a transporter as well.

In the case of regulated users, Law No. 142/94 and CREG Resolution 108/97 as amended compel companies to set a standard form contract subject to ex-ante control by the regulator to protect consumers from abusive clauses. This form must include:

- conditions to be met by the applicant for the service to be delivered and the property (including geographical area) to have the right to receive the service;
- the parties' obligations, duties and rights;
- exclusivity on the destination of the service;
- user's obligations in relation to the connection and its ownership;
- levels of quality and continuity of the service to subscribers or users;
- transcription of legal provisions applicable to the distributor's liability for failure to provide the service;
- causes and parties' rights for contract suspension or termination due to breach and facts allowing the company to impose sanctions on users and applicable procedure;
- form, time, place and manner and minimum content for invoicing the subscribers or users;
- rights and obligations relating to the installation, maintenance, replacement and control of the operation of the meters; and
- invoice payment guarantees by the subscriber or user if applicable.

One important addition to the contracting regime is an optional prepaid mode of contracting with end users (CREG Resolutions 96 of 2004 and 46 of 2012).

Law stated - 11 May 2026

REGULATION OF NATURAL GAS SALES AND TRADING

Ownership and organisation
What is the ownership and organisational structure for the supply and trading of natural gas?

There is no restriction on the national origin or legal nature of an owner of a natural gas supply or trading company. However, oil and gas exploration and production (E–P) must be conducted through a special-purpose oil and gas corporate vehicle established in Colombia, whether it be a Colombian corporation or a Colombian branch of a foreign corporation registered with the Colombian Ministry of Mines and Energy. Non-E–P companies trading in the wholesale natural gas market must incorporate a special-purpose vehicle in Colombia as a residential, public services stock-holding corporation (styled as a public services enterprise (ESP)).

Law stated - 11 May 2026

Government oversight
To what extent are natural gas supply and trading activities subject to government oversight? What authorisations are required to engage in wholesale trading of gas?

Law No. 142 of 1994 establishes that natural gas supply (including production, distribution and transportation) and trading activities are public services. A producer qua trader or a distributor must register as an ESP with the Public Residential Services (utilities) Superintendence (SSPD). For the specific purpose of trading, wholesale traders in either domestic or imported gas must also register before the Natural Gas Market Manager at the Colombia Mercantile Exchange to engage in wholesale trading. Natural gas supply and trading activities are subject to government oversight. Market agents must periodically provide reports related to transactional and operational information and financial statements to the SSPD. Additionally, Law No. 142 of 1994 requires suppliers and traders to hire an external auditor charged with filing an annual report to the SSPD on the given agent's management consistency with legal, technical, financial and accounting requirements. There are no recent initiatives to impose new requisites.

Law stated - 11 May 2026

Trading processes
How are physical and financial trades of natural gas typically completed?

According to the Energy and Gas Regulatory Commission (CREG) Resolution 102 015 of 2025 (also referred below as the Resolution), Colombia has a primary market primary supply market where natural gas producers-marketers and imported gas marketers offer natural gas for sale to the fuel gas public service. The Resolution is now the frame regulation applicable to Colombian natural gas wholesale market. Some of the main changes and restatements of prior regulations include:

1. Elimination of C1 (firm uninterrupted delivery with verified reserves) and C2 (firm portion and supplier option on variable portion) contracts and the annual auctions for these contracts.
2. The inclusion of requirements to evidence physical backup for imported gas. An importer is considered to have physical backup when, at the time of offering supply for a given period it has a contract guaranteeing access and the right to use international interconnection capacity or regasification infrastructure capacity. This enables marketing gas from the existing and future import infrastructure.
3. The only types of supply contracts that may be transacted in the primary market are:
    - firm supply contract with minimum payment of 95%, CF95;
    - firm supply contract with minimum payment of 80%, CF80 (newly included by Resolution 102 015, whereby firm supply without interruptions and with minimum monthly payment of 80% is contracted for a set period regardless of whether the gas is consumed or not);
    - gas purchase option supply contract against exports (OCGX);
    - contingency supply contract (CSC);
    - conditional firm supply contract (CFC);
    - gas purchase option supply contract (OCG);
    - contract for the supply of total production available for sale in tests; and
    - supply contract with interruptions (CSI).

All but the last type of supply contract above can be directly negotiated by the parties, provided that the Resolution's Title I's terms are observed. These terms are in general about the required structure and regulatorily required content of each contract as a condition of its registrability before the Gas Market Manager. Annex 1 of the Resolution explains the transactional and operational information required for contract registration with the Market Manager and market publicity needs.

In the secondary market, only the following types of contracts may be agreed:

- contract for firm supply or with firmness guarantee (CF);
- CFC;
- OCG;
- OCGX;
- CSC; and
- CSI.

Resolution 102 015 of 2025 lists the types of contracts for which having physical backup is obligatory, this being necessary for the registration and operation of supply contracts in the primary and secondary markets. Physical backup is defined as the certified evidence that a producer has Natural Gas Reserves (defined as the proven or probable reserves certified by the National Hydrocarbons Agency (ANH)) that a trader physically has natural gas or that a transporter physically has the transportation capacity to assume and comply with firm contractual commitments, or to ensure firmness from the moment deliveries begin until they cease.

Other changes and restatements of prior regulations include:

- The requirement for each source to report its total production available for firm sale includes the concept of "total production available for sale under testing", which is defined in the Resolution as the supply that the producer commits to deliver continuously and without interruptions during the field's extended testing period.
- Definition of mechanisms for accessing essential demand (by the SNT's compressor stations, residential and small commercial users, natural gas fuelled vehicles, and refineries excluding gas for their power self-generation). Resolution 102 015's Annex 8 sets the methodology for primary market sellers and buyers to prioritise essential demand supply when and if the Market Manager's commercial balance sheet shows deficit for a given standard market execution quarter.
- Modification of contract duration, which changes from one, two or more years to one or more standard quarters (namely, December–January–February, March–April–May, June–July–August and September–October–November).
- Flexibilisation of the periodic update of prices in initially agreed contracts. The equations for updating prices in contracts may be agreed by the parties applying frequencies of one standard quarter or more, or as freely agreed if the direct negotiation mechanism is used devoid of competitive bidding by interested parties. Annex 3 of the Resolution provides an update of equations methodology that may be used by the parties at discretion.
- Elimination of auctions and introduction of direct negotiations for interruptible contracts in the primary and secondary markets.
- Modification of the interruptible contract, establishing that it becomes firm on a daily basis when the following conditions are met simultaneously:
    - during the nomination cycle of the day prior to the gas day, the buyer nominates a gas quantity and the seller authorises the energy quantity to be supplied; and
    - the supply source used has natural gas reserves.
- For supply contract modalities involving imported gas, maintenance activities for import infrastructure will amount to 480 hours per year.
- There is no breach of supply when the nominated gas is delivered, regardless of the supply source, as long as this does not generate additional costs for the buyer.
- The Market Manager must perform the supply–demand balance for each of the next 40 trading quarters. If there is a supply deficit, essential demand must be prioritised according to the prioritisation procedure established by CREG.

Law stated - 11 May 2026

Available services and products

Must wholesale and retail buyers of natural gas purchase a bundled product from a single provider? If not, describe the range of services and products that customers can procure from competing providers.

In the wholesale natural gas market, buyers must separately purchase supply or transportation from a producer, gas importer or gas transporter. All contracts require that the gas be physically delivered. This conveys that the retailers and unregulated users will bear the risk of either purchasing excess gas or transportation capacity.

As per CREG Resolution 102 015 of 2025, a seller may offer the following gas supply contracts in the primary market:

- firm supply contract with minimum payment of 95%, CF95;
- firm supply contract with minimum payment of 80%, CF80 (newly included by Resolution 102 015 whereby firm supply without interruptions and with minimum monthly payment of 80% is contracted for a set period regardless of whether the gas is consumed or not);
- OCGX;
- CSC;
- CSI;
- CFC;
- OCG; and
- contract for the supply of the total production available for sale in tests.

In the secondary market, only the following types of contracts may be agreed:

- contract for firm supply or with firmness guarantee (CF);
- CFC;
- OCGX;
- CSC; and
- CSI.

Law stated - 11 May 2026

REGULATION OF LNG

Ownership and organisation

What is the ownership and organisational structure for LNG, including liquefaction and export facilities, and receiving and regasification facilities?

To ensure the power system's reliability and the construction of what is to date the only regasification plant in Colombia, the Energy and Natural Gas Regulatory Commission's (CREG) Resolution 62 of 2013 instated the "infrastructure agent". This agent is a public services enterprise (ESP) owned by private Colombian and Dutch investors, which built and are operating port infrastructure in the Caribbean for storing, regasifying and delivering imported natural gas to power plants or to the National Transportation System. There is a private infrastructure and importation services agreement between the infrastructure agent and certain geographically proximate thermal generators committing 350mcf/d gas for supply by the LNG plant. Payments under that agreement are also helped by a specific component in end-user tariffs until 2025, the continuity of which will then be revised by the regulator. The facility can currently regasifies 475mcf/d, such that the excess 75mcf/d capacity is available for the wholesale market and has been partially used since 2024.

Other LNG regasification facilities are currently under way in Colombia (it is reported that over 14 new LNG facilities have been or might be contracted in the near to midterm). Private companies for those facilities as well as imported gas traders are required to take the form of a stock-holding residential services enterprise (styled ESP) and to be registered with natural gas market manager in order to be able to contract supply agreements.

Law stated - 11 May 2026

Regulatory framework

Describe the regulatory framework and any relevant authorisations required to build and operate LNG facilities.

The following regulations and licences apply for an LNG port and inland facility:

- the Colombian National Maritime Direction's port approval;
- a National Environmental Licences Authority (ANLA) environmental licence;
- where the ANLA's licensing scope would not be encompassing, specific licences by local environmental authorities may be required (particularly for building the pipeline);
- if there is a pipeline connection, the Ministry of Mines and Energy (MME)'s approval of the layout;
- permits from national or local authorities regarding road and river crossings if there is a physical pipeline connection;
- MME's approval of a virtual pipeline (LNG trucking the regasification plant);
- Ministry of Transportation approval of vehicles for a virtual pipeline;
- Ministry of the Interior certification on prior consultation with indigenous and black communities neighbouring the project sites; and
- compliance during project performance of the Mining and Energy Planning Unit (UPME) and CREG regulations applicable to each of the facility's infrastructural and performance components.

Law stated - 11 May 2026

Pricing

Describe any regulation of the prices and terms of service in the LNG sector.

The remuneration structure used for the existing LNG regasification plant is based on its regasification capacity being committed to a group of thermal generators. This infrastructure's permanent availability for service is compensated by applying the expected annual income (IAE) agreed on award of the project by UPME. CREG regulations include that IAE component in end-user tariffs whose payments to the energy market in turn fund payments made by the power market's administrator to those thermal generators. This is a structure that could again be resorted for similar projects.

Otherwise, natural gas is supplied through the wholesale market where all traders including imported gas traders are subject to CREG regulations on types and market registration of contracts in the primary and secondary markets, to which certain pricing guidelines are applicable.

Note the following recent regulations:

- CREG Resolution 102 022 of 2025, which adjusted regulation to promote the long-term contract of imported gas, allowing the alignment of local contracts with LNG sales and purchase agreements; and
- CREG Resolution 101 100 of 2026, which specifically defines conditions for the transfer to the tariff of prices resulting from contract marketing mechanisms.

Natural gas transportation services are to be separately charged through a component of the transportation tariff charged by the project beneficiary as a transporter.

Law stated - 11 May 2026

MERGERS AND COMPETITION

Competition authorities
Which government body may prevent or punish anticompetitive or manipulative practices in the natural gas sector?

The Superintendence of Industry and Commerce has jurisdiction over general competition statutory laws.

The Superintendence of Residential Public Services may penalise infringements to and intervene parties infringing the Energy and Gas Regulatory Commission's (CREG) Resolution 80.

Law stated - 11 May 2026

Competition standards
What substantive standards does that government body apply to determine whether conduct is anticompetitive or manipulative?

The general competition statutory laws (Law No. 155 of 1959, Decree No. 2153 of 1992 and Law No. 1340 of 2009) and the residential public services (utilities) Law No. 142 of 1994 prohibit:

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agreements restricting the production, distribution, supply or consumption of commodities, products or services; and

- generally, all practices, procedures or systems that restrict competition in the market or that may determine unfair prices.

Additionally, Decree No. 2153 of 1992 sets a catalogue of conducts that are deemed anticompetitive, including agreements with that effect and abuses of dominant position.

CREG Resolution 80 of 2019 sets standards that compel market players to abstain from participating in acts, contracts or practices for the purpose of:

- eluding regulation on anticompetition;
- distorting the market's efficient functioning;
- misinforming or restricting access to the gas market;
- discriminating against market agents or restricting their market access; or
- restricting the offering of services in the market.

Law stated - 11 May 2026

Enforcement
What authority does the government body have to preclude or remedy anticompetitive or manipulative practices?

The Public Residential Services (utilities) Superintendence (SSPD) may, for the purpose of enforcing compliance, impose fines for up to approximately £28.14 million for 2026 (11,119,174 Colombian Basic Value Units (UVB), equal to COP12,100 or £.0025 at the applicable Colombian Market Representative Foreign Exchange Rate (TRM), which is a daily weighted rate of foreign currency operations transacted by Colombian financial institutions between the Colombian Peso and hard foreign currencies is published daily by the Colombian Superintendence of Finance).

For violations of CREG Resolution 80 of 2019, the SSPD may also:

- issue warnings;
- order the separation of a utility company's managers or employees from their posts;
- require government authorities to terminate the infringer or disable it to contract with the government;
- prohibit the direct or indirect rendering of utility services; and
- take the possession of the utility or suspend or terminate its authorisations or licences.

The Superintendence of Industry and Commerce (SIC) may also penalise anticompetitive conduct by a corporate entity with fines for up to approximately £28.14 million for 2025 (11,119,174 UVBs) or for up to 150% of profit derived from anticompetitive conduct. SIC may also order and instruct the infringer to cease and cure the infringement.

Law stated - 11 May 2026

Merger control

Does any government body have authority to approve or disapprove mergers or other changes in control over businesses in the sector or acquisition of production, transportation or distribution assets?

According to Law No. 1340 of 2009 and Resolution 2751 of 2021 the SIC Resolution 2751 of 2021, business mergers, consolidations, acquisitions of control or integration, whatever the legal form of the planned operation, must be reported for approval by SIC when the companies involved in the operation:

- carry out the same economic activity;
- are in the same value chain with effects on the national market; and
- during the fiscal year prior to the projected operation, one or all such companies or their affiliates have earned operating income or held assets in the same value chain within Colombia, greater than approximately £17.77 million for 2026 (7,074,307.43 UVBs, where one UVB is equal to 12,110 Colombian pesos or £0.0025 at TRM).

"Economic interest" by definition exists:

- when a transporter or its parents, subordinates or affiliates are parties to a profit-sharing or cost-cutting contract, or to any kind of risk-sharing contract with natural gas producers, traders or distributors;
- when a producer, trader or distributor:
    - has shares, quotas or parts of interest in a transportation company's equity for more than 25% of the capital stock;
    - is the transport company's creditor in terms more favourable than those prevailing in the market; or
    - has any influence on the determination of the price of the transportation or services offered by the transporter;
- when a transportation company has shares, quotas or parts of interest in the capital of a natural gas marketing, distributing or large consumer company for more than 25% of the total share capital; or
- when a producer owns shares in a distribution company in excess of 20% of its total share capital, or producers collectively own more than 30% of a distributor's shares capital.

Affiliation exists when companies are directly or indirectly subordinate or controlled by each other, this being presumed when:

- more than 50% of equity would be owned by the parents;
- the parents and the subordinates would jointly or separately hold minimum majority voting rights in the meeting of shareholders or would have the right to elect most members to the board of directors; or
- control would be exercised by another corporation through or with the cooperation of any of the above.

Moreover, the SSPD may apply rules on corporate affiliation set forth in the Colombian Tax Statute or in the Commercial Code. SSPD may also issue non-compliance warnings, impose fines of approximately £26 million for 2025 (100,000 Colombian current minimum monthly legal salaries, where one is equal to 1,432,500 Colombian pesos for 2025), issue orders to separate a utility company's managers or employees from their posts, require government authorities to terminate government contracts with an non-compliant party, disable it from further government contracting, prohibit it from directly or indirectly rendering utility services, and take possession of a utility for administration or liquidation, or suspend or terminate its authorisations or licences.

Law stated - 11 May 2026

Price restrictions
In the purchase of a regulated gas utility, are there any restrictions on the inclusion of the purchase cost in the price of services?

The criteria for the definition of tariffs are set in section 87 of Law 142 of 1994. Its section 87.4 requires that:

> tariff formulas be financially sufficient by guaranteeing the recovery of the costs and expenses of operation, including expansion, replacement and maintenance; [and] shall allow shareholders' equity to be remunerated in the same way as an efficient company in a comparable risk sector would have remunerated it.

The price of gas (including the price of manufactured gases, natural gas and liquefied petroleum gas) for sale to regulated users is determined in the market reflecting tariff formulas used by the parties in the unregulated market, or tariff formulas specifically approved for each relevant regulated market and distributor by CREG. These formulas allow factoring in the cost of acquisition of natural gas by the given market agent.

Accordingly, even though sales to unregulated users may be freely negotiated, the tariff may not include the cost of acquiring a utility because the regulation only allows that costs related to the service be included in the tariff.

Law stated - 11 May 2026

Corporate governance regulations
Are there any restrictions on the acquisition of shares in gas utilities? Do any corporate governance regulations or rules regarding the transfer of assets apply to gas utilities?

According to Law No. 1340 of 2009 and SIC Resolution 2751 of 2021, business mergers, consolidations, acquisitions of control or integration, whatever the legal form of the planned operation, must be reported for approval by SIC when the companies involved in the operation:

- carry out the same economic activity;
- are in the same value chain with effects on the national market; and
- during the fiscal year prior to the projected operation, one or all such companies or their affiliates have earned operating income or held assets in the same value chain within Colombia, greater than approximately £17.77 million for 2026 (7,074,307.43 UVBs, where one UVB is equal to 12,110 Colombian pesos or £0.0025 at TRM).

Also relevant to merger control is that articles 5 and 6 of CREG Resolution 57 of 1996 limit cross-ownership and corporate control of natural gas transportation companies regarding natural gas production, marketing and distribution companies. A natural gas transporter may not directly carry out production, marketing or distribution (or power generation) activities, nor may it have an economic interest in such companies. Symmetrically, natural gas producers, wholesalers, traders or distributors may not have an economic interest in a natural gas transporting company.

"Economic interest" is statutorily defined to exist when:

- a transporter or its parents, subordinates or affiliates are parties to a profit-sharing or cost-cutting contract, or to any kind of risk-sharing contract with natural gas producers, traders or distributors;
- when a producer, trader or distributor:
    - has shares, quotas or parts of interest in a transportation company's equity for more than 25% of the capital stock;
    - is the transport company's creditor in terms more favourable than those prevailing in the market;
    - has an influence on the determination of the price of the transportation or services offered by the transporter; or
    - has an influence on the determination of the price of transportation or of services offered by the transporter;
- when a transportation company has shares, quotas or parts of interest in excess of 25% of a natural gas marketing, distribution or large consumer company's equity; or
- when a producer owns shares in a distribution company in excess of 20% of its equity, or producers collectively own more than 30% of a distributor's equity.

Affiliation exists when companies are directly or indirectly subordinate or controlled by each other, which is presumed when:

- more than 50% of equity is owned by the parents;
- the parents and the subordinates jointly or separately hold minimum majority voting rights in the meeting of shareholders or have the right to elect most members of the board of directors; or
- control is exercised by another corporation through or with the cooperation of any of the above.

Law stated - 11 May 2026

INTERNATIONAL

Foreign participation
Are there any special requirements or limitations on foreign companies acquiring interests in any part of the natural gas sector?

There is no restriction on the national origin of foreign investment into the Colombian natural gas sector.

Law stated - 11 May 2026

International agreements
To what extent is regulatory policy affected by treaties or other multinational agreements?

Colombian natural gas regulation is not affected by any of Colombia's existing free-trade agreements or foreign-investment protection agreements.

Law stated - 11 May 2026

Cross-border sales and deliveries
What rules apply to cross-border sales or deliveries of natural gas?

The Energy and Natural Gas Regulatory Commission's Resolution 102 115 of 2025 applies the definition of a trader of imported gas as being an agent of the Colombian wholesale market allowed to sell imported gas in the same conditions as a local gas producer.

As for exports, producers may freely contract the transboundary supply of gas. However, Decree No. 1073 of 2015 rules under article 26 et seq on how the government may suspend exportation commitments when these could compromise supplying the national gas demand for internal consumption (eg, unavoidable risk or grave emergency situations).

Law stated - 11 May 2026

TRANSACTIONS BETWEEN AFFILIATES

Restrictions
What restrictions exist on transactions between a natural gas utility and its affiliates?

The Energy and Natural Gas Regulatory Commission (CREG) Resolution 57 of 1996 prohibits natural gas market agents from awarding preferential treatment in transactions with affiliates. In Colombian commercial law, affiliates are companies whose relationships are directly or indirectly subordinate or controlled. This is presumed when:

- more than 50% of equity are owned by the parents;
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the parents and the subordinates jointly or separately hold minimum majority voting rights in the meeting of shareholders or have the right to elect most members to the board of directors; or

- control is exercised by another corporation through or with the cooperation of any of the above.

The same CREG Resolution 57's articles 5 and 6 limit cross-ownership and corporate control of natural gas transportation companies regarding natural gas production, marketing and distribution companies. Accordingly, a natural gas transporter may not directly perform production, marketing or distribution (or power generation) activities, nor may it have an economic interest in such companies. Similarly, natural gas producers, wholesalers, traders or distributors may not be transporters or have an economic interest in a natural gas transporting company.

"Economic interest" is statutorily defined to exist when:

- a transporter or its parents, subordinates or affiliates are parties to a profit-sharing or cost-cutting contract, or to any kind of risk-sharing contract with natural gas producers, traders or distributors;
- a producer, trader or distributor:
    - has shares, quotas or parts of interest in excess of 25% of a transportation company’s equity;
    - is the transportation company's creditor in terms more favourable than those prevailing in the market; or
    - has an influence on the determination of the price of the transportation or services offered by the transporter;
- a transportation company has shares, quotas or parts of interest in excess of 25% of a natural gas marketing, distributing or large consumer company's equity; or
- when a producer owns shares in a distribution company in excess of 20% of its total share capital, or producers collectively own more than 30% of a distributor’s share capital.

Additionally, CREG Resolution 80 of 2019 prohibits cross-subsidies between market agents. It further requires that all situations of conflict of interest and the management thereof be revealed to the users, the CREG and the Public Residential Services (utilities) Superintendence (SSPD).

Law stated - 11 May 2026

Enforcement
Who enforces the affiliate restrictions and what are the sanctions for non-compliance?

SSPD may issue warnings and impose fines for up to approximately £28.14 million for 2026 (11,119,174 Colombian Basic Value Units, whereby one unit is equal to COP12,100 or £.0025 at the applicable Colombian Market Representative Foreign Exchange Rate, a daily weighted rate of foreign currency operations transacted by Colombian financial institutions between the Colombian Peso and hard foreign currencies that is published daily by the Colombian Superintendence of Finance).

It may also issue orders to separate a utility company's managers or employees from their posts, require government authorities to terminate government contracts with the infringer and disable it from further government contracting, prohibit that the infringer directly or indirectly render utility services, take possession of the utility for administration or liquidation, or suspend or terminate authorisations or licences.

Law stated - 11 May 2026

UPDATE AND TRENDS

Gas sector-specific regulation

Describe recent trends and developments in the regulation of the domestic natural gas sector.

Law 142 of 1994's general scope stands being to liberalise the natural gas utilities market and to enable private investment in the natural gas sector, as does having a technically regulated structure open to market agents regardless of national origin or investment source.

Countering a structural gas deficit in Colombia projected to increase through 2030, the Energy and Gas Regulatory Commission (CREG) has since 2024 to 2026 applied regulatory flexibility to facilitate timely supply, including through importation. The 2020 national gas supply plan is being executed and is now complemented through an indicative set of recommended infrastructure projects including LNG and potential pipeline importation of Venezuelan gas.

However, the current government's energy transition policy of not awarding any new hydrocarbons exploration and production contracts but rather relying on contracts existing in 2021 has deepened the country's exploration lag existing since 2016. In spite of new regulation meant to promote exploratory investment in prior contracts, foreign investment decreased by 42% between 2022 and 2025.

Government take has been on the rise over the years even before the current government, including because of premium and participation conditions set by the National Hydrocarbons Agency in area adjudication processes up to the last round in 2021. Furthermore, the corporate income tax has at minimum been 15% of accounting profit since the 2022 tax reform, or 35% of taxable income if greater.

And there is an issue on whether the current administration's express intent to directly fix tariffs in the gas and energy markets might materialise. This could occur if the Council of State (the highest administrative court) would reject the nullity suit against Decree 227 of 2023, whereby the President stated to be retaking regulatory functions to set tariffs (alleging these to have been only delegated to rather than bestowed upon CREG by operation of Law 142).

There has also been difficulty with permitting requirements and processes particularly regarding environmental licensing. A symptomatic example is the Komodo offshore field operated by Oxy with Ecopetrol, where late and complex licensing has all but suspended activities in one of the most promising exploration efforts meant to make Colombia self-sufficient again by 2030.

The current government's policy perspectives as implemented or intended would carry over to the new administration if the current president's political party's candidate is elected to take office on 7 August 2026. This situation will be monitored.

Law stated - 11 May 2026

Other regulatory developments of particular relevance to the gas sector

Describe any other recent regulatory trends and developments of particular interest to those operating in the domestic natural gas sector.

To better allocate gas available in Colombia considering its natural gas deficit, CREG has issued successive resolutions intended to provide marketing flexibility and efficiency for natural gas supply negotiations in the primary and secondary markets. Resolution 102 015 of 2025 is now the new framework regulation for the natural gas supply market structured to facilitate free contracting of short-term gas supply. Resolution 102 021 eases secondary market transportation capacity contracting by allowing free negotiation of duration and time intervals until the end of gas year 2030, and by extending the term for negotiating transportation capacity to 31 August 2026.

In the same direction, the Ministry of Mines and Energy issued Resolution 40163 on 18 March 2026 setting guidelines for thermal generators to offer imported gas in the secondary market if not needed to supply the power market, and for it to be transported. It also sets the terms for thermal generators to purchase imported liquefied petroleum gas replacing gas sold in the secondary market. This resolution will apply until CREG issues a final regulation on the matter within six months.

Law stated - 11 May 2026