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Venezuela's natural gas opening
From stranded endowment to strategic asset

Liliana Díaz



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Cover photo credit: Gas flares are seen at the state-owned oil company PDVSA, in Punta de Mata, Venezuela April 5, 2023. REUTERS/Leonardo Fernandez Viloria.

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Executive summary

Venezuela holds roughly 195–200 trillion cubic feet of proven natural gas reserves, the largest endowment in Latin America and among the ten largest in the world. It exports no pipeline gas and no liquefied natural gas (LNG). It flares or vents close to half of what it produces, and it delivers piped methane to only a fraction of its population. This is not, as is often assumed, a story of restrictive law or of sanctions alone. Venezuela's gas statute of 1999 is among the most liberal in the developing world; it permits full private ownership of non-associated gas ventures. That openness admittedly reaches only about one-fifth of the endowment upstream because four-fifths of Venezuela's gas is associated with oil and is extracted under the oil law. Yet the sector failed for a reason common to every molecule: the market built beneath both laws was designed around a single buyer. Petróleos de Venezuela, S.A. (PDVSA) Gas purchases essentially all gas—associated volumes once they leave the separator and non-associated volumes under long-term contracts—and resells it at administered prices, largely to state-owned heavy industry that does not pay. When the single buyer's balance sheet collapsed, so did the investment case for every molecule upstream of it.

The political rupture of January 2026 and the reopening of the sector to US and allied capital have created the first genuine opportunity in a generation to correct this design flaw. Across its three parts, this paper diagnoses the failure; quantifies what it costs Venezuela at home in flared gas, blacked-out cities, and constrained oil production; and assesses what the export window through Trinidad and Colombia is realistically worth. Its central argument is that gas, more than oil, is Venezuela's fastest route to fiscal oxygen and system-wide recovery, but only if policymakers dismantle the monopsony rather than merely refinance it.

The recommendations are deliberately modest in legislative ambition and demanding in execution: settle arrears credibly; let producers sell to buyers other than PDVSA Gas under the law that already permits it; stand up the regulator that already exists on paper; repair compression before drilling anything new; and anchor new supply to export netbacks that no domestic decree can confiscate. The asymmetry is already visible. By early September 2026, the oil sector had converted licenses into signed long-term instruments—among them twenty-five-year production participation contracts over Junín 5 and Bare and revised joint-venture terms with Chevron against more than $7 billion of planned investment—while the gas sector had not taken a single final investment decision (FID). The window will not stay open on Venezuelan time. Capital that does not find bankable terms in Caracas will find them on the US Gulf Coast, or in Qatar or Vaca Muerta. The binding constraint is no longer the supply of capital, which arrived in 2026, but the durability of the licenses and contracts that capital must underwrite.

Introduction: Why gas and why now

Purpose and audience

This paper is written for the people who will decide, over the next twenty-four months, whether Venezuela's natural gas endowment becomes an engine of national recovery or remains a stranded asset: oil and gas executives weighing capital allocation; US officials designing the sanctions relief architecture; Venezuelan policymakers, in government and in opposition, drafting the rules under which investment will or will not arrive; and the community of scholars who study hydrocarbon governance in Latin America. It unfolds in three self-contained parts, each ending with actionable recommendations and anchored in verifiable sources including Venezuelan academic scholarship, primary regulatory documents, operational data compiled from industry sources, think tank analysis, and the contemporaneous record of the post-January 2026 opening.

Three requirements recur across the recommendations that follow and are not argued separately: that fiscal terms, prices, and payment obligations be published rather than settled case by case; that the regulator the 1999 law already contemplates exercise the functions assigned to it; and that households, which today depend on liquefied petroleum gas (LPG) cylinders and an unreliable grid rather than on the gas the country produces, see the benefit. A reform that is opaque, unsupervised, or invisible to households might be executable but will not be durable.

This paper takes a position. Neutrality about facts does not require agnosticism about their implications. The facts assembled here support a strong conclusion: natural gas is the cheapest, fastest, and least politically contested lever available to stabilize Venezuela's energy system and public finances, and the current alignment of US licensing policy, investor interest, and regional demand is unlikely to recur if it is squandered.

Findings in brief

First, the root cause of the sector's failure is structural, not legal. The 1999 Organic Law on Gaseous Hydrocarbons is liberal by any international standard, but its upstream reach is narrower than commonly assumed: roughly four-fifths of Venezuela's gas is associated with oil, and its extraction falls under the oil law, most recently amended in January 2026. What broke the sector sits downstream of that boundary, in the commercial regime that receives associated gas the moment it leaves the separator and non-associated gas by contract: PDVSA Gas as sole offtaker of essentially all gas, buying under long-term contracts and reselling at prices set by ministerial decree, frozen for seventeen years between 2006 and 2023, largely to state-owned industrial customers operating under soft budget constraints. The predictable result was a chain of non-payment running from Corpoelec and the Corporación Venezolana de Guayana through PDVSA Gas to producers under the Cardón IV, Quiriquire Profundo, Yucal Placer, and Gas Guárico licenses, which accumulated arrears exceeding $3.5 billion to Eni and Repsol alone and destroyed the commercial logic of upstream investment. This is the same policy failure that hollowed out Egypt's gas sector in the 2010s. Egypt's subsequent recovery, in which production responded within months of credible arrears repayment, shows both the cost of the disease and the speed of the cure.

Second, the domestic costs are larger than commonly understood and are concentrated in three linked systems. Venezuela flares or vents on the order of 2 billion cubic feet per day, roughly half of gross production in recent years, primarily because more than half of the compressor fleet serving the Eastern Cryogenic Complex is out of service. The pipeline network, built to move gas to oilfields for reinjection rather than to distribute it to households, leaves the great majority of the population dependent on LPG cylinders. And the power system, nominally 30–34 gigawatts (GW) of installed capacity but with barely 40 percent available, cannot fuel its thermal fleet. The consequences follow in sequence: overexploitation of the Guri Reservoir, chronic blackouts, and, closing the vicious circle, power shortages that constrain oil production itself. Restoring the gathering-and-compression chain is the highest-return energy investment in Venezuela today, provided it is scoped as a chain: compression repaired in isolation moves the flare downstream to the extraction and fractionation trains rather than eliminating it. The first tranche is measured in hundreds of millions of dollars and months, not in billions and decades.

Third, exports are feasible, valuable, and, counterintuitively, the most credible source of pressure toward fixing the domestic market. The Trinidad route is no longer one project but an emerging cross-border province: Dragon, advancing toward an FID with drilling planned for 2027; the 7.3 trillion cubic foot (Tcf) Venezuelan Loran side of the unitized Loran–Manatee field, licensed in two phases during 2026 and developable as subsea tie-backs to Shell's Manatee platform, itself onstream in 2027; the remaining Mariscal Sucre fields; and BP's Cocuina–Manakin. Together these hold some 15–20 Tcf, enough to restore Trinidad's Atlantic LNG complex to its 12 million tonnes per annum (mtpa) nameplate by around 2030. With a rehabilitated Antonio Ricaurte pipeline to gas-short Colombia added, the routes represent on the order of $1.5–$2.5 billion per year in potential export value at plausible volumes and prices. More important than the revenue is the price signal. Export projects give producers a creditworthy counterparty other than PDVSA Gas and a netback that no domestic decree controls, which works on the monopsony from the outside rather than dissolving it. Realism is warranted on both scale and timing: the first Dragon gas has slipped toward

2029, greenfield Venezuelan LNG is not a proposition this decade, and every dollar contemplated for Venezuela competes with brownfield expansions on the US Gulf Coast, in Qatar, and in Argentina. But the brownfield, tie-back character of the Trinidad and Colombia routes is precisely what makes them survivable in a competitive market for capital.

Recommendations in brief

For Venezuelan policymakers: Do not rewrite the Gas Law; implement it. Authorize and enforce bilateral sales between producers and creditworthy buyers, with regulated third-party access to PDVSA Gas transport infrastructure. Convert the Ente Nacional del Gas (ENAGAS) from a paper entity into a functioning tariff regulator with a published methodology and automatic indexation. Put state-owned industrial consumers on hard budget constraints and replace blanket price subsidies with targeted support for LPG-dependent households. Settle producer arrears through crude-linked instruments now permissible under US licensing.

For US policymakers: Make the licensing architecture durable enough to be bankable, with multiyear terms, a clear successor-license policy, and explicit protection of contract sanctity. No board will sanction a thirty-year gas project against a license measured in months, and the record is explicit: the Trinidad authorizations were granted, amended, revoked, re-granted, and broadened five times between 2023 and 2026. Treat compression repair and flare capture as a strategic priority under General License 48A. It is the fastest methane-abatement opportunity in the hemisphere and directly serves US interests in Caribbean energy security.

For investors: The assets worth underwriting in this window share a template: existing resource delineation, short tie-back distances to functioning infrastructure, offtake anchored outside the Venezuelan domestic price regime, and no dependence on PDVSA Gas's balance sheet. Dragon, the Cardón IV expansion, the remaining Mariscal Sucre fields, and flare-capture ventures in Monagas meet that test; greenfield domestic market plays do not yet.

Part I. A liberal law, a captive market: Why Venezuela's gas sector failed by design

1. The puzzle of the generous law

Venezuela presents the analyst with a genuine puzzle. Its natural gas reserves, at approximately 195–201 Tcf, exceed those of the rest of South America combined and place it among the world's top ten holders.[1] Its governing statute for gas, the Organic Law on Gaseous Hydrocarbons of 1999, permits 100 percent private ownership of non-associated gas projects, a degree of openness that Brazil achieved only in 2021 and that Mexico, Colombia, and Argentina have never matched in upstream gas.[2] Under this law, nineteen exploration and production licenses were awarded to companies of the first rank: Repsol, Eni, TotalEnergies, Shell, Chevron, Gazprom, and Statoil.[3] And yet, a quarter-century later, only four of those licenses ever reached commercial production. Venezuela exports no natural gas. For eight years, from 2007 to 2015, the holder of the hemisphere's largest reserves was a net gas importer, buying Colombian gas through the Antonio Ricaurte pipeline until the contract lapsed in mid-2015. Gross output has fallen by roughly half since 2015.[4]

The reflexive explanations—resource nationalism, sanctions, and PDVSA's operational collapse—are real but insufficient. They explain the oil sector's trajectory well. They explain the gas sector's only partially, because gas enjoyed legal protections oil never had: to be precise, protections that cover the non-associated one-fifth of the resource, the associated remainder meeting the liberal law only after extraction, as Section 2.3 explains. Something else destroyed the investment case for Venezuelan gas and was at work on both sides of that legal line. Diagnosing it precisely matters because the remedy differs entirely depending on the diagnosis. If the law were the problem, the answer would be legislative reform—but it is not. The problem is the market structure built beneath the law, and the remedy is to dismantle that structure. This task requires administrative courage more than parliamentary arithmetic.

2. The endowment and its evolution, 1990–2025

2.1. A byproduct economy

Venezuelan gas has spent its entire modern history in the shadow of oil. Roughly 80–88 percent of the country's gas is associated (the estimates differ, with more recent estimates higher) and produced jointly with crude, and its traditional uses reflected that subordination: reinjection into reservoirs to sustain oil recovery, fuel for PDVSA's own operations, and feedstock for a petrochemical industry built around cheap molecules.[5] The gas that reached the market did so as a residual. Critically for what follows, the associated gas of the eastern basins is rich in liquids and the processing infrastructure Venezuela built in the 1980s and 1990s was designed above all to recover them. This includes the extraction plants at Jusepín, Santa Bárbara, and San Joaquín, and the four world-scale fractionation trains at the José complex, with 200,000 barrels per day (b/d) of installed capacity, from which the country derives the LPG that most households use for cooking.[6] Pipeline methane, by contrast, was never built out as a national distribution system. It instead follows a corridor connecting fields to oil operations, thermal plants, and heavy industry.

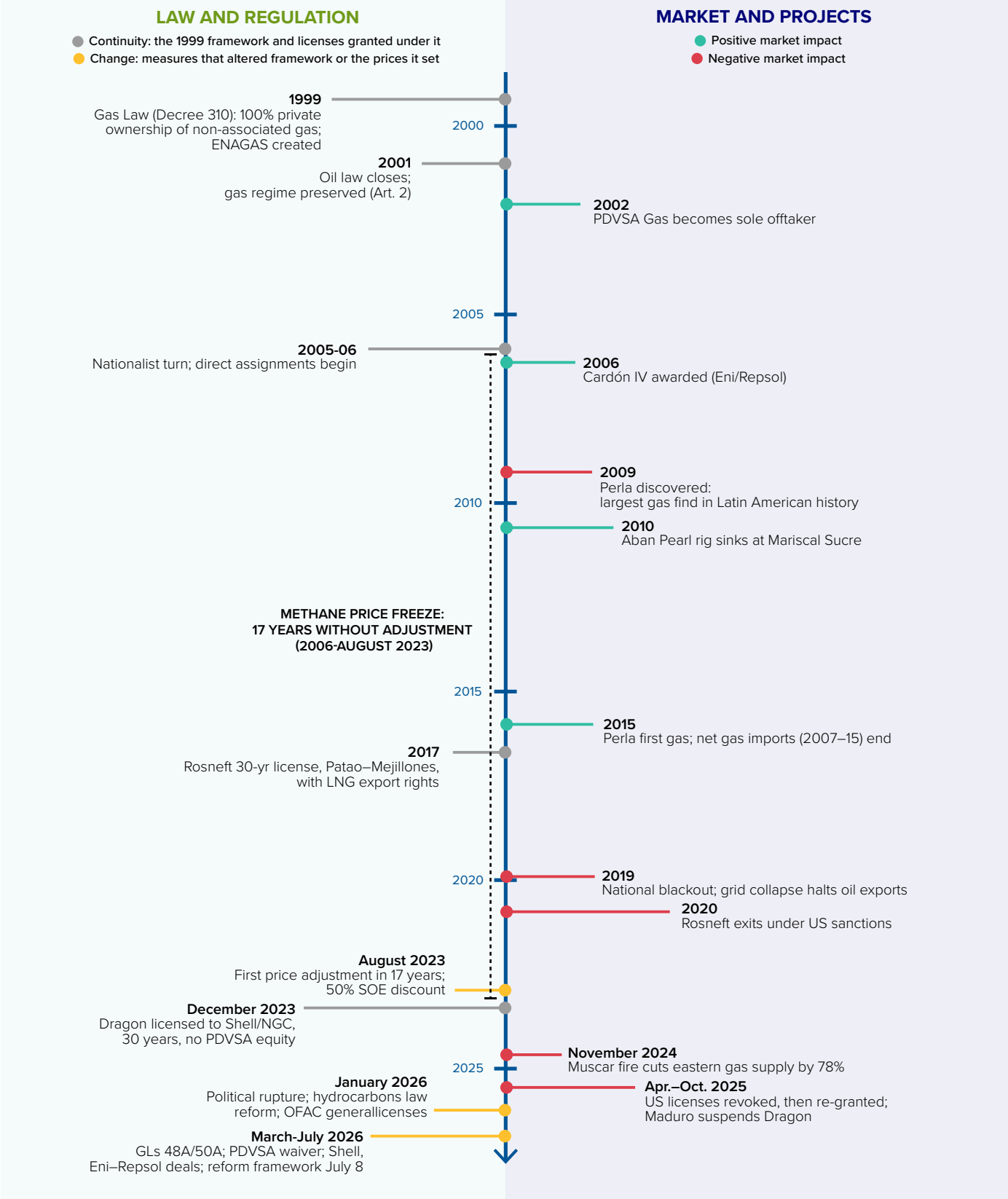
Under the nationalized regime of 1971–1999, gas development was reserved to the state and remained an afterthought. By the 1990s, three pressures converged to force a rethink: growing electricity demand that hydropower alone could not securely meet; PDVSA's lack of capital and specialized expertise for offshore gas and LNG; and the demonstrated success of the Apertura oil policy in attracting foreign investment after 1993.[7]

2.2. Openness by design: The 1999 Gas Law

The resulting statute deserves more attention than it receives because its architecture is the baseline against which every reform proposal should be judged. Decree 310 of September 23, 1999, the Ley Orgánica de Hidrocarburos Gaseosos—published in Official Gazette No. 36,793 with regulations following in June 2000—was enacted in the first year of the Hugo Chávez presidency, before the resource-nationalist turn of 2001.[8] It did five things that remain in force today.

- It affirmed state ownership of gas in the ground while declining to reserve exploitation to the state. This created a licensing system under which private companies, including foreign ones, can explore for and produce non-associated gas with 100 percent ownership. Licensing is done by ministerial authority alone, without National Assembly approval.
- It reserved to the state an option of 35 percent participation at the development stage, exercised in practice through PDVSA, as at Cardón IV. This is an option, not a mandate.
- It set fiscal terms deliberately lighter than oil's, with a 20 percent royalty against the oil sector's eventual 30 percent, in recognition of gas projects' longer cycles and heavier infrastructure burden.
- It created a sector regulator, ENAGAS, with functional autonomy but attached to the Ministry of Energy and Mines (currently the Ministry of Petroleum), five directors appointed ministerially, and a tariff role confined to drafting the bases on which the ministries would set prices (refer to Articles 12, 36, 37.6, and 39).

Figure 1: A liberal law, a turbulent market: Venezuela's gas sector, 1999–2026



The 1999 legal framework survived every subsequent shock; what changed was the market and licensing environment built around it.
Sources: Regulatory chronology in notes 2, 8–9, 13, 23–24; project record in Table 1 and Part III.

- It prohibited, in Article 9, the same entity from simultaneously controlling production, transportation, and distribution in a single region without ministerial authorization. This is an explicit safeguard against vertical integration.

When the 2001 Organic Hydrocarbons Law closed the oil sector to private majority ownership, its Article 2 expressly preserved the Gas Law's regime for non-associated gas. The 2006 forced migration of oil operating agreements to PDVSA-majority joint ventures likewise left gas licenses untouched.[9] The gas framework survived every wave of nationalization essentially intact. On paper, it is still one of the most investor-friendly gas statutes in the Global South. Figure 1 displays the law's remarkable durability against the turbulence that surrounded it.

2.3. One resource, two laws: The associated gas question

An honest account of the framework must confront a fact that flatters neither the law nor the standard telling of it: upstream, the liberal regime just described governs only about one-fifth of the resource. Roughly 80 percent of Venezuela's gas is associated. Article 2 of the 2001 Organic Hydrocarbons Law draws the boundary explicitly: activities relating to gaseous hydrocarbons are governed by the Gas Law, except the extraction of associated gas, which follows the oil statute. Associated gas is therefore produced inside the oil regime, by PDVSA and its majority-held joint ventures, under oil law fiscal terms. The January 2026 reform, for all its sweep, kept this perimeter: it regulates crude and associated gas but, in the words of counsel summaries, it leaves the Gas Law in force and effect, with no changes to the legislation governing non-associated gas.[10]

The boundary is physical as much as legal. Venezuelan practice, confirmed by the sector's engineers, treats the first separator as the point of transfer: once associated gas is separated from crude at the surface, it enters the domain of the Gas Law, whose scope expressly covers gathering, compression, treatment, processing, transport, distribution, and commercialization of gas of any origin. The classification of reservoirs is less tidy. Condensate-rich accumulations sit in a gray zone between free and associated gas for which the ministry has never published clear criteria, an ambiguity with real fiscal and contractual consequences for any field near the line.[11]

Three implications follow, and they organize much of what this paper argues. First, the celebrated openness of the 1999 law was always an offer addressing a minority of the molecules; the majority reach the market as a byproduct of oil ventures whose contracts, capital plans, and remuneration are written in crude. Second, the failure diagnosed in Section 3 is not thereby diminished but relocated: the monopsony operates downstream of the separator, in Gas Law territory, where associated and non-associated gas alike converge on a single buyer at a decreed price. The design flaw is common to the whole resource. Third, the January 2026 reform changes the upstream terms of the associated four-fifths, cutting the headline royalty to a negotiable ceiling of 30 percent assessed on volumes extracted and not used in operations, a base that exempts reinjection and fuel and thereby, for the first time in the oil regime, stops taxing gas that a venture chooses to conserve rather than flare. In this respect, the reform brings associated gas in line with non-associated gas, which has received the same treatment since 1999, when Article 34 of the Gas Law confined the royalty to volumes extracted and not reinjected. Whether this new incentive to conserve gas translates into lower flaring and more supply to market depends on the contract renegotiation examined in the recommendations below.[12]

2.4. Nineteen licenses, four producers

Between 1999 and the early 2020s, the ministry awarded nineteen non-associated gas licenses—initially through competitive rounds and, after the 2005–2006 nationalist turn, increasingly by direct assignment.[13] Table 1 summarizes the principal awards and their fate.

The pattern in Table 1 is this paper's first analytical finding. The conversion rate from license to commercial production, four of nineteen, is roughly one in five—far below what a resource base of this quality and a fiscal regime of this generosity should deliver.[14] Some failures were geological (as in the case of Urumaco), some were infrastructural (such as Deltana blocks stranded far from shore), and one was operationally tragic: the Aban Pearl rig sank in 2010 during PDVSA's solo attempt at Mariscal Sucre.[15] But the licenses that found gas ran into the same wall. It is that wall, not geology and not the law, that explains the aggregate outcome.

The ownership churn recorded in Table 1 is itself diagnostic. Every category of exit is represented: geological relinquishment (Gazprom at Urumaco); sanctions-forced divestiture (Rosneft's 2020 transfer of its Patao–Mejillones position to a Russian state vehicle, whose residual claims now complicate re-licensing); strategic retreat from the broader Venezuelan risk (TotalEnergies and Equinor booked a combined exit from Petrocedeño in 2021, with Total taking a $1.38 billion capital loss while retaining only its gas positions); and, most recently, portfolio reshuffling under the 2026 opening (Chevron trading its dormant Loran gas stakes for expanded Orinoco oil positions).[16] Over twenty-five years, this liberal licensing regime produced not a gas industry but an archive of departures. That only changed when the class of investor changed in 2023–2026 to companies whose business case does not run through the domestic market at all.

3. Diagnosis: One buyer, one decree

3.1. How the market actually works

Every license listed above, whatever its ownership, sells its gas to a single counterparty: PDVSA Gas, the subsidiary created in 2002 to manage the commercial gas chain. PDVSA Gas produces only a fraction of the country's gas itself. Its role is to buy essentially all of it, both associated volumes surrendered by PDVSA's oil operations under internal arrangements and non-associated volumes purchased under long-term contracts from licensees, and then to transport, distribute, and

Table 1: Principal non-associated gas licenses under the 1999 Gas Law: Award, ownership evolution, and status

Project/area	Licensees at award	Ownership evolution	Status (2026)
Yucal Placer Norte and Sur (Guárico, onshore, 2001)	Total-led consortium with Repsol and Venezuelan partners (Ypergas as operating vehicle)	TotalEnergies disclosed a 69.5 percent interest at its 2021 Venezuela oil exit	One of the few producing licenses; modest volumes for the domestic market
Cardón IV and Perla (Gulf of Venezuela, offshore, 2006)	Eni 50 percent and Repsol 50 percent	PDVSA exercised its 35 percent back-in at development: Eni 32.5 percent, Repsol 32.5 percent, and PDVSA 35 percent	Producing about 580–650 million cubic feet per day (MMcf/d), roughly one-third of all gas consumed in Venezuela; tripartite agreement signed in March 2026
Quiriquire Profundo (Monagas, onshore)	Repsol 60 percent	Stable	Limited production and exploration
Gas Guárico and other onshore areas	Domestic and mixed consortia	Various	Marginal or dormant
Rafael Urdaneta blocks: Urumaco I and II (Gulf of Venezuela, 2005)	Gazprom	Relinquished after unsuccessful exploration	Abandoned
Rafael Urdaneta: Cardón III	Chevron	Dormant	No development
Patao and Mejillones (Mariscal Sucre, offshore)	Rosneft (thirty-year license, December 2017, with LNG export rights; about 180 billion cubic meters (bcm) in place)	Rosneft exited Venezuela in March 2020 under US sanctions, transferring assets to Russian state vehicle Roszarubezhneft; residual claims remain a legal encumbrance	Stalled; Shell in talks (2026) for the fields
Plataforma Deltana blocks (offshore east)	Chevron 60 percent (Block 2, Loran); TotalEnergies 49 percent and partners (Block 4, Cocuina); Statoil and others elsewhere	Cross-border unitization with Trinidad: Loran–Manatee (2010), Cocuina–Manakin (2015). Chevron relinquished its Loran-area stakes in a 2026 asset swap for Orinoco heavy-oil positions; Loran re-offered and awarded in two phases (August 2026): Phase 1 to Shell, Phase 2 to BP, XRG (ADNOC) and UCC in equal interests with BP as operator, the license interest transferred from PDVSA Gas. BP sold 20 percent of Cocuina–Manakin to the National Gas Company of Trinidad (NGC)	Loran licensed in two phases, to be developed in parallel; Trinidad-side Manatee under development by Shell (FID 2024)
Blanquilla–Tortuga (offshore)	Conceptual LNG partners, including discussions with multiple international oil companies (IOCs)	Never advanced past planning	Abandoned
Mariscal Sucre: Dragon (offshore northeast; about 12 Tcf across the four Mariscal Sucre fields)	Retained by PDVSA after IOC bids failed to materialize in 2011	Dragon licensed in December 2023 for thirty years to Shell (70 percent) and NGC of Trinidad (30 percent) with no PDVSA equity; suspended by Nicholás Maduro in October 2025; revived under the 2026 opening	Advancing toward FID; drilling tendered July 2026

Sources: Compiled from the regulatory history in notes 3, 8–9, 13 and 15–16; corporate disclosures and project documentation cited in note 16 and in Part III. Ownership percentages as publicly reported; several minor licenses omitted for concision.

resell the gas across the domestic market.[17] There is, to this day, no operating contract between a private producer and a third-party buyer in Venezuela.[18] The license contracts themselves contemplate third-party sales and even exports "once the domestic market is satisfied," a condition no authority has ever defined, leaving the escape clause permanently ambiguous. The 2026 agreements at Cardón IV restate the same sequencing of domestic supply first and exports later, without making the condition measurable: neither the partners nor the ministry has published the terms, and the obligation remains as indeterminate as it was when the licenses were written.[19] The absence is contractual and administrative rather than statutory: Article 29 of the Gas Law expressly permits producers of associated or non-associated gas to contract supply to any holder of a ministerial permit, and Article 10 already obliges transporters and distributors to grant access to spare capacity. This is precisely where the seam runs between the two laws of Section 2.3. Associated gas leaves the oil regime at the separator and enters the Gas Law's commercial chain, where the only counterparty waiting is PDVSA Gas; non-associated gas arrives at the same node by contract. Whatever a molecule's legal upbringing, it converges on the same buyer.

This design was not irrational at inception. In the early 2000s, PDVSA was one of the most creditworthy counterparties in Latin America and concentrating offtake risk on its balance sheet was arguably the only way to make twenty-year gas sales agreements financeable for fields serving a shallow domestic market.[20] The single-buyer model has worked elsewhere under one condition: that the single buyer pays. What Venezuela demonstrates, and what makes it a textbook case rather than a curiosity, is what happens when the anchor buyer's creditworthiness evaporates while the structure that depends on it remains legally frozen in place.

3.2. What theory would have predicted

The Venezuelan arrangement belongs to a family of market designs with pathologies economists have mapped closely, and economic theory predicts its trajectory with uncomfortable precision. A monopsonist buys below the competitive price because it can; producers respond by supplying less and investing less than the resource would justify. When the monopsonist is also state owned, a second failure compounds the first: what economist János Kornai called the soft budget constraint. An enterprise that expects to be rescued does not need to collect from its customers, and customers who expect the same indulgence do not need to pay. Arrears become the equilibrium, not the anomaly.[21] The World Bank issued precisely this warning in 2000, reviewing single-buyer designs across the developing world: the model concentrates payment risk in one entity, invites political interference in pricing, weakens payment discipline down the whole chain, and loads contingent liabilities onto the state.[22] Add the time-inconsistency problem inherent in administered pricing, because a ministry that can decree a price today can freeze it tomorrow, and investors price that possibility into every dollar they decline to commit. The puzzle of Section 1 dissolves. Venezuela's gas sector did not fail despite its design; it failed through it.

3.3. The price that bankrupted the buyer

PDVSA Gas's insolvency was not an accident of mismanagement alone; it was manufactured by the pricing regime. Domestic methane prices and transport and distribution tariffs are set by ministerial resolution. In practice, ENAGAS—the nominal regulator—neither sets nor indexes them. Prices were not adjusted at all between 2006 and August 2023: seventeen years of nominal freeze through episodes of hyperinflation reduced bolívar-denominated tariffs to fractions of a cent.[23] When the government finally moved, the resolution of August 29, 2023, (Official Gazette No. 42,702) set industrial and commercial methane prices between $0.13 and $2.34 per million British thermal units (MMBtu), still well below any plausible long-run supply cost for new gas, and, remarkably, granted state-owned companies a 50 percent discount even on these tariffs.[24] The Oxford Institute for Energy Studies documented the mechanics of the squeeze more than a decade ago: by 2014 the regulated wellhead price had eroded to $0.127 per MMBtu against a consumer price of $0.784, with PDVSA absorbing the gap. That structure made offshore gas, with a supply cost a multiple of either figure, undevelopable for the domestic market by construction.[25]

The discount is the tell. The heavy industrial demand base to which PDVSA Gas sells—power generation through Corpoelec, the Guayana steel and aluminum complex, the Pequiven petrochemical system, cement, and refining—is overwhelmingly state owned. Industry participants estimate that well above 90 percent of large-consumer offtake sits inside the state perimeter.[26] Operational data compiled from industry sources confirm the concentration: of roughly 1,712 MMcf/d sold into the internal market in 2025, some 1,442 MMcf/d, or 84 percent, went to state-sector consumers, compared to 270 MMcf/d to private buyers.[27] These state customers, themselves decapitalized and loss making, do not pay their gas bills in full or on time. PDVSA Gas, squeezed between contracted purchase obligations to producers and uncollectable receivables from state consumers priced below cost, did what every insolvent single buyer does. It stopped paying upstream.

3.4. Arrears, barter, and the slow strangulation of Cardón IV

The clearest evidence sits in the accounts of the sector's flagship. Perla, discovered in 2009 in the Cardón IV block, was the largest gas find in Latin American history at roughly 17 Tcf in place. It reached production in 2015 in an industry-leading five years, under a Gas Sales Agreement with PDVSA running to 2036 with phased plateaus of 450, 800, and ultimately 1,200 MMcf/d.[28] It never reached the third phase, not because the reservoir disappointed but because the buyer could not pay. PDVSA's debts to Eni for Perla gas reached approximately $3 billion by the end of 2025, while Repsol reported €586 million.[29] For years the parties resorted to barter, crude oil and refined product cargoes accepted in lieu of cash under spe-

cific US authorizations, until Washington revoked those authorizations in March 2025, leaving the debts to compound with no repayment channel until the post-January 2026 licenses restored oil-for-gas settlement.[30] A field capable of 1.2 billion cubic feet per day (Bcf/d) has spent a decade producing half of that, and its owners have spent a decade financing the Venezuelan state involuntarily.

In consulting terms, Venezuela did not lack a gas market. It had one with a single point of failure, and the failure occurred. Every subsequent pathology in the sector—the licenses that never advanced, the flaring examined in Part II, and the export projects deferred for fifteen years—traces back through this node.

3.5. A regulator on paper

The Gas Law's institutional design anticipated exactly this risk and provided the instrument to manage it: an autonomous ENAGAS reviewing tariffs and supervising open access. But this instrument was never used. ENAGAS's board is ministerially appointed. Its tariff role was never conferred in the first place, with Article 12 reserving price and tariff setting to the ministries and leaving ENAGAS to draft the bases. And from 2004 onward, the offices of minister of petroleum and president of PDVSA were frequently held by the same person, collapsing policymaker, regulator, and dominant operator into one chair.[31] Venezuelan legal scholarship has documented this institutional hollowing in detail: the regulatory function did not fail because it was never activated.[32] The consequence for investors is precise. There is no independent forum in which a producer, a would-be marketer, or a large consumer can obtain a tariff ruling, an access order, or contract enforcement against PDVSA Gas. Regulatory risk in Venezuela's gas sector is not volatility; it is a vacuum.

Venezuela's configuration—liberal upstream terms, a single state buyer, administered prices below cost, and arrears to international companies—is not unique. Its closest analogue offers both a warning and an encouragement, and it is examined in Box 1.

Box 1. The Egyptian mirror

The Egyptian Natural Gas Holding Company (EGAS) occupied precisely PDVSA Gas's position as the sole purchaser of production shares and reselling into a heavily subsidized domestic market. When fiscal stress hit, EGAS accumulated arrears to foreign producers that reached $6.1 billion by mid-2024, after an earlier arrears crisis that peaked in the mid-2010s. Production sagged from more than 6.6 Bcf/d to about 4.1 Bcf/d as companies declined to invest against a non-paying counterparty.[33]

The instructive part is the recovery. When Cairo committed to a credible, scheduled repayment program, and arrears fell to roughly $714 million by April 2026, incremental production responded within months. The petroleum ministry attributed some 200 MMcf/d of restored gas output directly to the clearance of arrears.[34]

Two lessons transfer directly to Caracas. Upstream capital is unforgiving about counterparty credit but forgiving about history: it returns quickly once payment is credible. And no amount of geological endowment or fiscal generosity substitutes for a buyer who pays. Venezuela's advantage over Egypt is that it can pair arrears settlement with structural reform and plural buyers, rather than merely recapitalizing the same single point of failure.

4. What is broken and what is not

It is worth being explicit about the division between what is and isn't broken because reform capital is scarce and should not be spent fixing what works.

Not broken: The Gas Law itself is not broken, nor are the licensing instrument; the fiscal terms (a 20 percent royalty is competitive); the legal permission for third-party sales and exports; and the survival, through everything, of technically capable international operators inside the country. Eni, Repsol, Shell, Chevron, and TotalEnergies legacy partners remain present—an asset most post-crisis producers would envy.

Broken: The monopsony offtake structure and its corollary, the absence of any bilateral producer-consumer contracting, are broken. So are the administered price regime, which is unindexed and set below cost, with deeper discounts for precisely the customers least likely to pay; soft budget constraints across the state-owned demand base; the commercial invisibility of associated gas, which is produced by ventures remunerated in crude and handed over at the separator so that no participant in the chain that yields four-fifths of Venezuela's gas earns anything by capturing it; the dormant regulator; and, downstream of all of these, PDVSA Gas's balance sheet, which cannot anchor a single additional dollar of long-term offtake.

The diagnosis yields a design principle for everything that follows in this paper. The objective of reform is not to make PDVSA Gas solvent enough to resume its old role; it is to make the sector's revenues independent of PDVSA Gas's solvency. A rival principle is now being tested in the oil sector and is examined in Box 2.

5. Recommendations: Implement the law

1. Settle arrears first, structurally, not ad hoc. Use the settlement channels reopened by the 2026 US general licenses. Crude-linked repayment is again permissible and Eni has confirmed the mechanism's restoration to convert the roughly $3.5–$4 billion owed to Cardón IV's partners and other creditors into a scheduled, published instrument, ideally one collateralized against export receivables as they emerge.[36] Egypt's experience suggests the supply response begins with the credibility of the schedule, not its completion.[37]

2. Activate bilateral contracting under existing law. No legislative act is required for a producer to sell to Corpoelec, Pequiven, a private industrial, or an exporter. The licenses' domestic market satisfaction clause requires only a ministerial determination that has never been issued. Issue it. Define the domestic supply obligation as a transparent, volumetric first call—not a blanket assignment of all molecules to PDVSA Gas—and let everything above it clear bilaterally. Whether the 2026 Cardón IV agreements did so cannot be established because their terms have not been published. An undisclosed first call is no more bankable than an undefined one, and the sector's flagship transaction has so far supplied neither the number nor the precedent.

3. Impose regulated third-party access to transport. The Gas Law does more than lean against vertical integration in Article 9. Article 10 already obliges transporters and distributors to grant access where capacity is available, and Article 37 makes tariff proposals and open access express ENAGAS functions. What is missing are a tariff and a forum, not a statute. Convert PDVSA Gas's pipeline and processing system into a tariffed common carrier, legally unbundled first and structurally later, so that a bilateral contract is physically executable. Without access, contracting freedom is decorative.

4. Resurrect ENAGAS as a real tariff authority. Publish a tariff methodology with automatic indexation, move price-setting from ministerial resolution to regulatory determination, and staff the board for fixed terms. This is the cheapest reform on the list and the one that most changes the risk perception of every counterparty.

5. Harden budget constraints before raising prices further. The August 2023 adjustment showed prices can move; the 50 percent state-owned enterprise (SOE) discount showed why moving them changes little. Eliminate the SOE discount and require payment guarantees or escrowed collections from state consumers (the power-sector mechanism is detailed in Part II). Target subsidy where it is socially defensible, in LPG for households, rather than where it is fiscally corrosive.

6. Write associated gas into the joint-venture renegotiation. The 180-day review of *empresas mixtas* and production contracts opened by the January 2026 reform is the only realistic vehicle for reaching the associated four-fifths of the resource, and it will not recur. Renegotiated contracts should give ventures explicit commercial title to their gas at the separator, the right to sell it to any authorized buyer or exporter rather than surrender it to PDVSA Gas, and fiscal treatment that applies the reform's own royalty base, which exempts gas used in operations, so that capturing gas is taxed only when it is monetized and flaring it is never the cheaper option.[38] The vehicle is now demonstrably operable and closing. On September 2, 2026, Eni completed the first migration under the new regime, converting the Petrojunín joint venture into a twenty-five-year production participation contract over Junín 5 with Eni as exclusive operator. GeoPark signed a comparable contract over Bare two days later, and Chevron settled revised terms across its three joint ventures. Each of those negotiations was an opportunity to assign commercial title to associated gas, but there is no public indication that any of them did so. The implementing regulations for the January reform were still being drafted as late as April 2026, by PDVSA's own account, which means the window was open while the rules were unwritten.[39] Every compression and flare-capture project in Part II depends on someone owning the gas it saves.

None of these steps requires a new law, a constitutional moment, or a resolved political settlement. All of them require the state to give up discretionary control over gas flows and prices. That is why they have not happened and why the post-January 2026 environment—in which external anchors such as US licensing conditions, IOC negotiating leverage, and export project finance can substitute for absent domestic institutions—is

Box 2. The institutional shortcut

In August 2026, Washington and Venezuela's interim authorities announced an arrangement: seventeen fields and a stated 65 billion barrels were assigned to a single private operator, North American Blue Energy Partners, with a US agency holding 35 percent of its corporate parent, a US veto over board appointments, a US citizen board majority, and a contract under US law and enforced by US courts. The White House described hundred-year concessions, while Caracas described a twenty-five-year agreement. PDVSA's president confirmed on September 7, 2026, that the contract runs twenty-five years and is renewable. Venezuelan law does not provide for concessions at all, and the January 2026 reform permits only production participation contracts.[35]

The architecture is an attempt to import an institutional framework rather than build one, and gas shows precisely where the import stops. Foreign governance over a producer can substitute for a missing court or a missing counterparty. It cannot set a domestic tariff, compel third-party access to a pipeline, or activate a dormant regulator. Venezuela's gas failure sits downstream of the producer, at the node this section has just described, and nothing in this architecture reaches it.

The comparison also flatters the gas projects. Dragon, Cardón IV, and the Mariscal Sucre fields are non-associated licenses under a 1999 statute that survived four waves of nationalization, granted by ministerial act, with cross-border unitization agreements ratified years ago. In a sector in which every instrument signed in 2026 carries successor government risk, these licenses are the most durable paper in Venezuela.

the most favorable moment to attempt them since 1999. The limits of that substitution should be stated plainly because they are easily overread. External anchors work where they replace a missing counterparty or discipline a particular transaction: an export offtaker supplies a netback no ministry sets; an escrow supplies a treasury that pays; or a foreign-law contract supplies a court. They do not work where they are asked to replace the state's regulatory function. No governance structure imposed on a producer sets the price of methane, compels access to a pipeline, or causes ENAGAS to issue a tariff. Those remain Venezuelan decisions and the recommendations above are addressed to whoever will take them.

Part I has located the failure at a single node: a buyer who cannot pay, protected by a price no one can correct. Part II follows the consequences downstream, into the flare stacks of Monagas, the darkened grid, and the oilfields that cannot run without either.

Notes to Part I

1. Venezuelan reserves exceed 60 percent of Latin America's total, per Organization of the Petroleum Exporting Countries (OPEC) Annual Statistical Bulletin and US Energy Information Administration data as compiled in "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," research brief on file with this report's author, January 2026; Luisa Palacios, "Venezuela: The Post-Maduro Oil, Gas and Mining Outlook," *Americas Quarterly*, January 4, 2026, https://www.americasquarterly.org/article/venezuela-the-post-maduro-oil-gas-and-mining-outlook.https://www.americasquarterly.org/article/venezuela-the-post-maduro-oil-gas-and-mining-outlook/
2. Ley Orgánica de Hidrocarburos Gaseosos, Decreto No. 310, Gaceta Oficial No. 36,793 (September 23, 1999), http://www.enagas.gob.ve/info/marcolegal/pubdocs/ley-organica-de-hidrocarburos-gaseosos.pdf; Reglamento de la Ley Orgánica de Hidrocarburos Gaseosos, Gaceta Oficial Extraordinaria No. 5,471 (June 5, 2000)
3. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Sections 4-5.
4. Ibid., Section 4.3.
5. Ibid., Section 10.1; "Venezuela Natural Gas Sector," research brief on file with this report's author, July 2026; Orlando A. Ochoa, "Venezuela's Oil and Gas Industry: The Challenge of Sustainable Recovery," Oxford Institute for Energy Studies, August 2026, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2026/08/SP37-Venezuelas-Oil-and-Gas-Industry.pdf. PDVSA's own 2026 estimate, cited in the Oxford Institute report, is 193.39 Tcf proved, of which approximately 87.8 percent is associated. The *Exposición de Motivos* of the 1999 Gas Law put the associated share at 90 percent. ENAGAS and Igor Hernández, "Incentivos Económicos, Implementación de Políticas y 'Cuellos de Botella' en la Industria del Gas Natural en Venezuela" in Ronald Balza Guanipa and Oswaldo Felizzola, eds., *Gas Natural en Venezuela: Incentivos, Regulación y Transición Energética* (Caracas: Universidad Católica Andrés Bello, 2024), https://abediciones.ucab.edu.ve/wp-content/uploads/2025/06/Santiago-Fontiveros.pdf. This last source describes roughly 20 percent as non-associated This paper uses the lower associated share throughout as the conservative case.
6. Santiago Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," in Balza Guanipa and Felizzola, eds., *Gas Natural en Venezuela: Incentivos, Regulación y Transición Energética,* 177–180.
7. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Section 2.
8. Ley Orgánica de Hidrocarburos Gaseosos, Articles 1, 9, and 23–24 and fiscal provisions, http://www.enagas.gob.ve/info/marcolegal/pubdocs/ley-organica-de-hidrocarburos-gaseosos.pdfhttps://www.enagas.gob.ve/info/marcolegal/pubdocs/ley-organica-de-hidrocarburos-gaseosos.pdf.
9. Ley Orgánica de Hidrocarburos (2001), Article 2, https://www.minhidrocarburos.gob.ve/wp-content/documentos/leyes/leydehidrocarburos.pdf; "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Sections 6.16.3.
10. Extraction of associated gas is governed by the oil law. Ley Orgánica de Hidrocarburos (2001), Article 2. The bifurcated regulatory structure has persisted since its original design. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," sections 6.1–6.2. The reformed law "regulates only crude oil and associated gas" and "does not apply to non-associated natural gas," with a 180-day adjustment period for existing mixed companies and production contracts. "Venezuela's Hydrocarbons Law Reform: What Businesses Need to Know," Baker McKenzie, March 2, 2026, https://www.bakermckenzie.com/en/insight/publications/2026/03/reform-organic-hydrocarbons-law-venezuela. As of April 2026, no announcements or changes had been made to the legislation governing non-associated gas. "Energy Reform in Venezuela," Baker McKenzie, April 13, 2026, https://www.bakermckenzie.com/en/insight/publications/resources/energy-reform-in-venezuela.
11. Igor Hernández, "Incentivos Económicos, Implementación de Políticas y 'Cuellos de Botella' en la Industria del Gas Natural en Venezuela" in Balza Guanipa and Felizzola, eds., *Gas Natural en Venezuela,* 65. The Gas Law's upstream competence covers only non-associated gas; ENAGAS estimates roughly 20 percent of reserves are non-associated. Associated gas passes to Gas Law treatment "una vez pase del primer separador"; absence of clear ministerial criteria for classifying condensate-rich reservoirs as free or associated gas. Author interview with Rubén Pérez, Venezuelan gas-sector engineer and analyst, 2026.
12. "The Gaseous Hydrocarbons Law remains in force and effect"; a royalty of up to 30 percent, set per project by the National Executive, applies on "volumes of hydrocarbons extracted and not used in operations," payable in kind or in money. Alexandre R. Chequer, et al., "Venezuela Transforms Hydrocarbons Sector with New Hydrocarbons Law Amendment," Mayer Brown, February 4, 2026, https://www.mayerbrown.com/en/insights/publications/2026/02/venezuela-transforms-hydrocarbons-sector-with-new-hydrocarbons-law-amendment.
13. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Sections 4.1–4.3.
14. Ibid., Section 4.3.
15. Ibid., Section 5.2.

16. "Rosneft and PDVSA Signed Heads of Agreement for Joint Development of the Offshore Natural Gas Project in Venezuela," Rosneft, press release, February 20, 2016, https://www.rosneft.com/press/releases/item/180805; "Igor Sechin Makes Business Trip to Venezuela," Rosneft, press release, December 17, 2017, https://www.rosneft.com/press/releases/item/189217/. For the thirty-year Patao–Mejillones license with LNG export rights, about 180 bcm in place, and the termination of Venezuelan operations and asset sale to a Russian state-owned company, see: "Rosneft Sells Its Venezuelan Assets and Becomes an Owner of 9.6% of its Share Capital," Rosneft, press release, March 28, 2020, https://www.rosneft.com/press/releases/item/200275/. For the $1.38 billion capital loss, retained 69.5 percent Yucal Placer interest, and 49 percent Plataforma Deltana Block 4 interest, see: "Venezuela: TotalEnergies Exits Petrocedeño," TotalEnergies, press release, July 29, 2021, https://totalenergies.com/newsroom/venezuela-totalenergies-exits-petrocedeno/?lang=eng; "Equinor Completes Divestment of Onshore Asset in Venezuela," Equinor, July 20, 2021, https://www.equinor.com/news/archive/202107-completes-divestment-onshore-asset. For Chevron relinquishing Loran-area stakes in an Orinoco asset swap, Loran to be re-offered, and Russian-held stakes being a remaining hurdle, see: Curtis Williams and Marianna Parraga, "Shell in Advanced Talks with Venezuela for More Gas Areas, Sources Say," Reuters, April 1, 2026, https://www.reuters.com/business/energy/shell-advanced-talks-with-venezuela-more-gas-areas-sources-say-2026-04-01/. On the Dragon equity split recorded in Table 1, see Part III, note 11. On the 2026 Loran awards recorded in Table 1, see Part III, note 17.
17. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Section 7.2; Author interview with Rubén Pérez.
18. "En el país aún no hay un contrato entre un productor y un tercero." Author interview with Rubén Pérez.
19. Ibid. License terms permit third-party sales and export "siempre y cuando el mercado interno esté satisfecho," a condition never operationally defined. On the 2026 position: Eni reports that Cardón IV signed a "sustainability agreement" providing for expanded Perla production, increased domestic volumes and conditions for future gas exports, without disclosing those conditions. "Eni Signs Strategic Contract in Venezuela and Becomes Operator of the Super Giant Junín-5 Oil Field," Eni, press release, September 2, 2026, https://www.eni.com/en-IT/media/press-release/2026/09/eni-signs-strategic-contract-in-venezuela-and-becomes-operator-of-the-super-giant-junin-5-oil-field.html. The publicly stated plan is a production ramp from about 580 to 645 MMcf/d followed by further drilling and infrastructure work, described by the project manager at the Venezuela Energética conference on April 27, 2026. Will Faulkner, "Eni–Repsol JV Targets Higher Gas Output from Venezuela's Cardon IV Field," Chemanalyst News, April 28, 2026, https://www.chemanalyst.com/NewsAndDeals/NewsDetails/eni-repsol-jv-targets-higher-gas-output-from-venezuela-cardon-iv-field-41934; Vivian Sequera and Marianna Parraga, "Eni Signs Agreement to Relaunch Heavy Oil Project in Venezuela," Reuters, April 28, 2026, https://www.reuters.com/business/energy/eni-signs-agreement-relaunch-heavy-oil-project-venezuela-2026-04-28/; "Venezuela Hopes to Double Cardón IV Gas Output," Argus, April 27, 2026, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2819708-venezuela-hopes-to-double-cardon-iv-gas-output. No published source sets out the agreement's contractual conditions, and the domestic-supply obligation therefore remains undefined.
20. Offtake was assigned to PDVSA Gas at award because "PDVSA tenía músculo financiero" at that time. License terms permit third-party sales and export "siempre y cuando el mercado interno esté satisfecho"; no authority has clarified when the condition is met. Author interview with Rubén Pérez.
21. János Kornai, "The Soft Budget Constraint," *Kyklos* 39, 1 (1986), 3–30, https://onlinelibrary.wiley.com/doi/10.1111/j.1467-6435.1986.tb01252.x.
22. Single-buyer designs weaken payment discipline and impose contingent liabilities on the state. Laszlo Lovei, "The Single-Buyer Model: A Dangerous Path toward Competitive Electricity Markets," World Bank, December 1, 2000, https://www.semanticscholar.org/paper/The-Single-Buyer-Model-%3A-A-Dangerous-Path-toward-Lovei/75e3917ce76dd4c5dc1c72d26edfa7f81b9ed22c. On the time-inconsistency of host-state commitments toward sunk-cost investors, the classic statement is: Raymond Vernon, *Sovereignty at Bay: The Multinational Spread of U.S. Enterprises* (New York: Basic Books, 1971).
23. "Gobierno Venezolano Aumenta Tarifas de Gas Metano Después de 17 Años," Reuters, August 31, 2023, https://es-us.noticias.yahoo.com/gobierno-venezolano-aumenta-tarifas-gas-222334555.html. Tariffs denominated in bolívares "que se ha devaluado cientos de veces." Author interview with Rubén Pérez.
24. Ibid. For the $0.13–$2.34 per MMBtu range, methane prices, and transport and distribution tariffs, see: "Resolución del Ministerio del Poder Popular de Petróleo," Gaceta Oficial No. 42,702, August 29, 2023, https://finanzasdigital.com/gaceta-oficial-n42-702-transferencia-de-actividades-de-exploracion-extraccion-y-transporte-de-crudo-a-petrosur-s-a/; For the 50 percent tariff for state-owned enterprises, see: Author interview with Rubén Pérez.
25. The 2014 wellhead price was $0.127 per MMBtu vs. a consumer price of $0.784 per MMBtu. Venezuela was a net gas importer 2007–2015 via the Antonio Ricaurte pipeline. PDVSA's froze all LNG export projects in September 2011. Anouk Honoré, "South American Gas Markets and the Role of LNG," Oxford Institute for Energy Studies, October 2016, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/10/South-American-Gas-Markets-and-the-Role-of-LNG-NG-114.pdf.
26. More than 90–95 percent of large consumers are state enterprises: Corpoelec, Guayana steel and aluminum, Pequiven petrochemicals. Author interview with Rubén Pérez.
27. PDVSA Gas operational data, 2015–2025, compiled by industry sources (dataset on file with author). See Table 2, Part II of this paper.
28. "Eni Starts Production at Perla Giant Gas Field Offshore Venezuela," Eni, press release, July 6, 2015, https://www.eni.com/en-IT/media/press-release/2015/07/eni-starts-production-at-perla-giant-gas-field-offshore-venezuela.html; "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Section 5.1.
29. For Eni at $2.3 billion by June 2025 and about $3 billion by the end of 2025, and Repsol at €586 million, see: "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Section 5.1; Repsol, Full-Year 2025 Results webcast transcript, March 2026 (on file with author).
30. For the March 2025 revocation of oil-for-gas authorizations, see: "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Section 8.3; Rubén Esteller, "Repsol y ENI Apuestan por el Gas Venezolano con un Nuevo Acuerdo para Explotar su Principal Activo en el País," *elEconomista*, March 13, 2026, https://www.eleconomista.es/energia/noticias/13822974/03/26/repsol-y-eni-apuestan-por-el-gas-venezolano-con-un-nuevo-acuerdo-para-explotar-su-principal-activo-en-el-pais.html.
31. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," Sections 7.1–7.3.

32. See the essays collected in Balza Guanipa and Felizzola, eds., *Gas natural en Venezuela,* including contributions by César R. Mata García on regulation, Tahío Méndez Sergent on the institutional framework, and Igor Hernández on incentives and bottlenecks (files are with author).
33. For arrears of $6.1 billion in June 2024, and a production decline from more than 6.6 to about 4.1 Bcf/d, see: Mostefa Ouki, "Egypt: A Return to a Balanced Gas Market?" Oxford Institute for Energy Studies, June 2018, https://www.oxfordenergy.org/publications/egypt-return-balanced-gas-market/. For arrears reduced to about $714 million by April 2026, and a ministry attribution of about 200 MMcf/d incremental gas to arrears clearance, July–October 2024, see: Sarah Samir, "Egypt Zeroes out IOC Arrears," Egypt Oil & Gas, June 2026, https://egyptoil-gas.com/news/egypt-zeroes-out-ioc-arrears.
34. Ibid.
35. For seventeen fields, "100-year concessions," 65 billion barrels, 35 percent equity to the Office of Strategic Capital, 20 percent of offtake at production cost and right of first refusal on the remainder, board veto and US-citizen majority, US law and US jurisdiction, see: "Fact Sheet: Historic Oil Agreement to Secure American Energy Dominance and Drive Venezuela's Economic Recovery," White House, August 31, 2026, https://www.whitehouse.gov/fact-sheets/2026/08/fact-sheet-president-donald-j-trump-announces-historic-oil-agreement-to-secure-american-energy-dominance-and-drive-venezuelas-economic-recovery/. For twenty-five years, seventeen fields, more than 1.5 million b/d, $209,335 million in state revenue at $65 per barrel, eight greenfield blocks at 16 percent royalty and 34 percent income tax, see: "Presidenta Delcy Rodríguez se dirige al país sobre el gran acuerdo energético con EE. UU.," Ministerio del Poder Popular del Despacho de la Presidencia, August 31, 2026, https://presidencia.gob.ve/evento=32908. For concessions unavailable under Venezuelan law, production participation contracts only, potential conflict with Article 303 of the constitution, the interim authorities' mandate, and the legal analysis, see: José Ignacio Hernández, "Understanding the Implications of the U.S.–Venezuela Oil Deal," Center for Strategic and International Studies, September 4, 2026, https://www.csis.org/analysis/understanding-implications-us-venezuela-oil-deal ; For transparency, legality, fiscal terms, legitimacy and counterparty, PDVSA's September 7 clarification that the contract runs twenty-five years and is renewable, see: Luisa Palacios, "The US-Venezuela Oil Deal Might De-Risk Oil Company NABEP but Not Venezuela," Center on Global Energy Policy, September 9, 2026, https://www.energypolicy.columbia.edu/the-us-venezuela-oil-deal-might-de-risk-oil-company-nabep-but-not-venezuela/. This paper takes no position on the agreement's validity under Venezuelan law.
36. Esteller, "Repsol y ENI Apuestan por el Gas Venezolano con un Nuevo Acuerdo para Explotar su Principal Activo en el País"; "Consolidated Chart of Venezuela General Licenses," Bracewell LLP, April 2026, https://info.bracewell.com/40/2962/uploads/bracewell-consolidated-chart-of-venezuela-general-licenses.pdf.
37. Arrears arise through four links and four sets of actors. Price setting: the Ministry of Petroleum, not ENAGAS, fixes methane prices at the production and processing centers and, jointly with the Ministry of Production and Commerce, the transport and distribution tariffs charged to final consumers; ENAGAS only drafts the bases (Ley Orgánica de Hidrocarburos Gaseosos, Articles 12 and 37.6). Prices went unchanged from 2006 to August 2023 and, when adjusted, were set at $0.13–$2.34 per MMBtu with a 50 percent discount for state-owned buyers. "Resolución del Ministerio del Poder Popular de Petróleo"; "Gobierno Venezolano Años," Reuters, August 31, 2023, https://es-us.noticias.yahoo.com/gobierno-venezolano-aumenta-tarifas-gas-222334555.html). Collection: the buyers at those prices are overwhelmingly state entities (Corpoelec, the Guayana steel and aluminum complex, Pequiven) operating under soft budget constraints, and PDVSA Gas, itself state-owned, collects a fraction of what it invoices them. Transmission: PDVSA Gas nonetheless owes contracted payments to licensees under long-term gas sales agreements, so the shortfall accumulates as producer receivables, principally to Eni and Repsol. Settlement: with bolívar-denominated obligations eroded by hyperinflation, payment migrated to crude and product cargoes under specific US authorizations, revoked in March 2025 and restored under the 2026 general licenses. See: Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 182; Hernández, "Incentivos Económicos, Implementación de Políticas y 'Cuellos de Botella' en la Industria del Gas Natural en Venezuela," 65–68.
38. Ley Orgánica de Hidrocarburos, Article 2.; "Evolution of Venezuela's Natural Gas Regulatory Framework," Sections 6.1–6.2.; "Venezuela's Hydrocarbons Law Reform"; "Energy Reform in Venezuela."
39. For the twenty-five-year production participation contract with PDVSA Petróleo over the Bare block, see: "GeoPark Announces Major Strategic Entry into Venezuela," GeoPark, press release, September 2, 2026, https://www.geo-park.com/press_releases/geopark-strategic-entry-into-venezuela/. For the revised fiscal, commercial, and legal terms across the joint ventures, and Carabobo-1 and Carabobo-2-South-A assigned to Petroindependencia, see: "Chevron Expands Position in Venezuela," Chevron, press release, September 2, 2026, https://www.chevron.com/newsroom/2026/q3/chevron-expands-position-in-venezuela. On the state of the implementing rules, PDVSA's executive vice president told the Venezuela Energética conference on April 27, 2026, that regulations tied to the oil reform law were still under development. Faulkner, "Eni–Repsol JV Targets Higher Gas Output from Venezuela's Cardon IV Field."

Part II. Gas at home: Flaring, power, and the domestic foundations of recovery

1. A country that burns what it lacks

The domestic gas economy that the market structure described in Part I can be captured in a single, uncomfortable ratio: in recent years Venezuela has flared, vented, or otherwise wasted an amount of gas approaching what it has sold. Gross production of roughly 3.9–4.0 Bcf/d in 2024–2025 yielded internal-market sales of about 1.7 Bcf/d, with close to 2.0 Bcf/d lost to flaring and venting and only a residual share consumed productively within PDVSA's own operations.[1] A country with the hemisphere's largest reserves burns off, unpriced, a volume comparable to Colombia's entire national consumption.[2] Meanwhile its thermal power plants run short of fuel, its households queue for LPG cylinders, and its oil production is throttled by the unreliability of the grid.

This installment maps that domestic economy: who consumes gas, through what infrastructure, and at what loss. It then draws out the three-way dependency at the heart of Venezuela's recovery problem: no gas, no power; no power, no oil; no oil, no fiscal capacity to fix the gas. The dependency is usually described as a vicious circle, but it is more useful to see it as a leverage point. Because the systems are coupled, the cheapest intervention—restoring gas compression—propagates through all three.

2. The anatomy of domestic consumption

2.1. What the data show

Table 2 assembles the most granular operational series available for the past decade.

Three features of this table carry the installment's argument. First, the halving of gross production since 2015 tracks the collapse of oil output, as it must when four-fifths of gas is associated. Second, the near disappearance of PDVSA's own use is itself a symptom of infrastructure failure. Reinjection, which historically absorbed 40–60 percent of gross production and peaked at 60 percent in 2009, fell from more than 3 Bcf/d to a few hundred MMcf/d, with direct consequences for oil recovery in pressure-dependent reservoirs. Third, and most striking, flaring and venting did not fall proportionally with production. As output halved, waste held roughly constant near 2–2.9 Bcf/d, so the share of production wasted rose from less than 30 percent to roughly half.[3] Waste in Venezuela is not a fixed friction; it is the system's default disposal route when the machinery that moves gas to market stops working.

2.2 A corridor, not a web

The state sector's 84 percent share of internal sales (Table 2) decomposes, per the same dataset's classification, into power generation, steel and aluminum, cement, refining and upgrading, petrochemicals, and compressed natural gas (CNG) for vehicles, with private offtake confined to gas distributors and miscellaneous industry.[4] Households barely appear in the methane balance, and the reason is physical before it is economic. The transmission network was engineered mid-century to link gas supply to oil operations and later to thermal plants and the Guayana industrial pole. It runs as a corridor, not a web (Figure 2). Building capillarity, city gates, medium-pressure rings, and last-mile distribution was never the system's purpose, and the residential market was served instead through the liquids chain: natural gas liquids (NGLs) extracted in the eastern cryogenic plants, fractionated at José, and delivered nationwide as LPG in cylinders.[5]

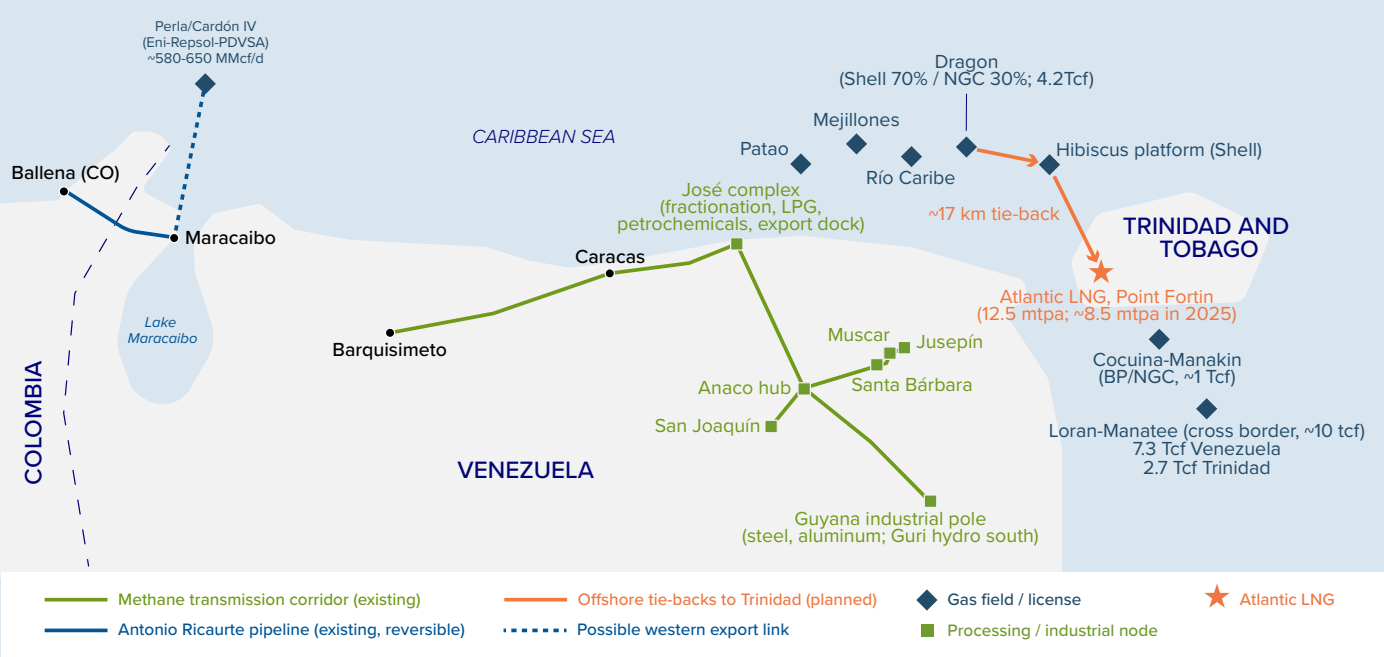
This has two policy implications that are routinely missed. Roughly 90 percent of the population relies on LPG for cooking

Table 2. Venezuela natural gas balance, 2015–2025 (MMcf/d, annual averages)

	2015	2017	2019	2021	2023	2024	2025
Gross production	7,756	7,439	5,493	4,444	4,049	3,895	3,961
Internal market sales: State sector	2,012	2,158	1,477	1,279	1,387	1,374	1,442
Internal market sales: Private sector	295	250	219	283	257	255	270
Internal market sales: Total	2,307	2,408	1,696	1,562	1,644	1,629	1,712
PDVSA own use (reinjection, fuel, natural gas liquids processing)	3,172	2,602	1,089	179	334	227	255
Flared, vented, and losses	2,277	2,429	2,708	2,703	2,071	2,039	1,994
Memo: Gas to power generation	938	959	550	534	600	702	693

Source: PDVSA Gas operational data, 2015–2025, compiled by industry sources (dataset on file with author). Figures are internally consistent within the dataset; minor residuals reflect measurement and shrinkage. Cross-checks against US Energy Information Agency and Energy Institute series confirm the direction and magnitude of the production decline.

Figure 2: Venezuela's gas geography: A corridor at home, tie-backs abroad (schematic, not to scale)



The pipeline system links eastern production to oil operations, thermal plants, and heavy industry rather than to the population. The offshore fields of the northeast sit within short tie-back distance of Trinidad's underused processing and liquefaction complex, and the Antonio Ricaurte pipeline already connects the west to Colombia. *Sources:* notes 5–6; Part III, notes 11–23.

and the liquids chain has been failing them. National LPG output collapsed from about 105,000 b/d in 2016 to roughly 20,000 b/d by 2022 against demand near 55,000 b/d, with the country—which was self-sufficient until 2009–2010—depending on US imports until the 2019 sanctions prevented them.[6] Because households live on the cylinder, the socially sensitive gas price in Venezuela is the LPG price, not the methane tariff. Methane price reform is therefore more politically feasible than commonly assumed, provided LPG support is protected. And every barrel of LPG consumed domestically at subsidized prices is a barrel of NGLs unavailable for higher-value petrochemical feedstock or export from José's dedicated dock, an opportunity cost that will grow as the liquids chain recovers.[7]

3. The machinery of waste

3.1. Compression as the binding constraint

The proximate cause of Venezuela's flaring is neither geological nor commercial but mechanical. Associated gas in the eastern producing areas—above all Monagas Norte—must be compressed to enter the gathering and processing chain that runs through the Jusepín, Santa Bárbara, and San Joaquín extraction plants toward Anaco and José. More than half of the compressor park serving this Eastern Cryogenic Complex requires urgent repair or replacement; when compression fails, the only physical alternative at the wellhead is the flare stack or the vent.[8] Compression is the binding constraint but not a sufficient one. Captured rich gas still requires the extraction trains, the fractionation capacity at José, serviceable delivery, and reinjection compression. Where those are unavailable, restored compression relocates the flare rather than extinguishing it. Sanctions aggravated the problem disproportionately here because the installed compression is largely US-technology equipment for which parts, warranties, and service became unobtainable, and Chinese substitution proved impractical.[9] The system has been kept alive by improvised reconfiguration, relocated units, and emergency tie-ins, much of it undocumented except in the memory of the engineers who executed it. Any recovery program must treat that fragility as a knowledge-retention problem, not merely a procurement one.[10]

The fragility is not hypothetical; it has a casualty record, examined in Box 3 (next page). A system that concentrates two-thirds of national supply in one unmaintained facility is not an infrastructure network; it is a hostage situation. Every recovery plan should treat redundancy at these nodes as a first-order design requirement.

Beneath the mechanical cause sits a commercial one, and Part I's legal geography explains it. Nearly all of the flared gas is associated gas, produced by PDVSA and the oil joint ventures under contracts denominated in crude. The gas itself, once separated, passes into a chain in which the administered price is close to zero, PDVSA Gas pays late or not at all for what it buys and collects little for what it delivers, and subsidies to domestic gas consumption averaged some $1.4 billion per year from 2010–2021. In this arithmetic, no participant earns anything by compressing a molecule instead of burning it. The flare is not only a symptom of broken machinery but the rational disposal route of a resource the market has been instructed to treat as worthless.[13]

Box 3. Pigap 2 and Muscar: Anatomy of a fragile system

In March 2021, a rupture at the Pigap 2 high-pressure compression complex shut in up to 560 MMcf/d from the Furrial and Quiriquire fields. A follow-on blast took down as much as 1 Bcf/d of associated gas and 20,000 b/d of light crude.[11]

In November 2024, a fire at the Muscar complex, a single node handling on the order of 65 percent of national gas supply, cut eastern associated gas production by 78 percent, from roughly 2.3 Bcf/d to 500 MMcf/d, and cascaded instantly into gas-fired power plants and the José petrochemical complex.[12]

These two episodes, three years apart, offer the same lesson: in a network without redundancy, every maintenance failure is a national energy event.

Two data points calibrate both the scale and the tractability of the flaring problem. Venezuela was the world's fourth-largest flaring country in 2025 in absolute terms, alongside producers with many times its oil output. Adjusted for production, it is not merely near the top of the league table but off it: the World Bank's flaring database records a 2022 flaring intensity of 33.53 cubic meters per barrel, the highest of any country measured, across 103 identified flare sites, with intensity having quadrupled between 2012–2021 and no official PDVSA flaring data published since 2016.[14] PDVSA Gas's own limited repair campaigns in recent years cut flaring by roughly 0.5 Bcf/d, proof at operating scale that compression restoration converts directly into marketable gas.[15]

One complication that deserves honest treatment is that the gas arriving at the eastern plants has been getting leaner. Liquids content in parts of Monagas Norte has fallen from the 3.0–4.0 gallons per million (GPM) range the extraction plants were designed for to 1.5–2.0 GPM, which degrades the economics of the NGL chain. Compressor rehabilitation must therefore be planned as an integrated system optimization, deciding which units to repair, replace, or relocate against actual suction pressures and gas quality, rather than as a like-for-like restoration.[16] The fix is fast but it is not naïve.

3.2. What the waste is worth

At Henry Hub-linked reference prices, the roughly 2 Bcf/d recently vented or flared (half of gross production per the operational data in Table 2) represents on the order of $2 billion per year in forgone gas value alone—before any discount for Venezuelan netbacks, before counting the liquids stripped out of rich gas, the diesel burned in generators substituting for absent gas-fired power, and the oil production lost to inadequate reinjection.[17]

The environmental ledger is equally stark. Venting releases methane, a greenhouse gas with more than eighty times the twenty-year warming potency of carbon dioxide (CO_2), making Eastern Venezuela one of the largest single methane abatement opportunities in the Western Hemisphere. This is the rare case in which the economic and environmental arguments are not in tension; they are literally the same project. International climate finance, methane-focused facilities, Article 6 mechanisms, and the World Bank's flaring reduction partnership architecture can legitimately co-fund what is simultaneously a commercial venture, provided credible measurement is established.[18] The hook already exists. In its second Nationally Determined Contribution of October 2025, Venezuela pledged to cut venting and flaring by 71 percent by 2030 from 2024 levels, a commitment that, based on the numbers in Table 2, is achievable only through precisely the compression and gathering program described here and gives any government in Caracas an internationally legible framework under which to seek co-financing for it. That commitment has since acquired a counterweight. In September 2026, Venezuela contracted incremental oil production that would approach a doubling of national output by the end of the decade. A pledge to cut flaring by 71 percent and a plan to double oil production over the same horizon are reconcilable only through the gathering and compression program described here, a point Venezuela's own vice minister for gas made at the April 2026 Caracas conference when she called for accelerated infrastructure recovery and for projects to improve the handling of associated gas.[19]

4. The power nexus: No gas, no power; no power, no oil

4.1. A hedge dismantled from both ends

Venezuela's electricity system was designed around a sound hedge. Hydropower supplied cheap baseload from roughly 17 GW of installed capacity, more than half of it at a single plant, the 10 GW Guri complex in southern Bolívar state. A thermal fleet distributed across the country served as insurance against drought.[20]The hedge was dismantled from both ends. The 2007–2010 nationalizations consolidated the sector into Corpoelec, froze tariffs, and ended effective investment. Installed capacity on paper reached 30–36 GW, but available capacity collapsed to roughly 40 percent of that—around 10.5 GW—at the nadir of the 2019 national blackout, with thermal availability falling hardest.[21] Steam turbine availability at the major plants fell from 30 percent in 2013 to less than 13 percent by 2016 as preventive maintenance was abandoned.[22] Deprived of thermal insurance, system operators overexploited the Guri Reservoir beyond its firm-energy design year after year, converting El Niño droughts in 2010 and 2016 into national rationing crises and leaving the country acutely exposed to the intensifying hydrological volatility that climate projections assign to the Orinoco Basin.[23] Transmission tells the same story: the 765 kilovolt (kV) backbone grew less than 8 percent between 1998–2014 against a growing and shifting load, and the 2019 collapse propagated through exactly this brittle, unmaintained network. Rehabilitation now has a counterparty. On September

2, 2026, GE Vernova agreed to bring one gigawatt online within twenty-four months and a further five over the following four years, covering thermal and hydroelectric generation, transmission and distribution, and key substations. The commitment is real but also modest against the gap documented above (roughly one-tenth of it in the first phase) and thermal capacity restored without gas to fire it restores nothing.[24]

4.2 Fuel starvation

The thermal fleet that survives is fuel starved, and the fuel it lacks is gas. The National Assembly's bipartisan commission on the electricity crisis calculated that the thermal park requires at least 1,500 MMcf/d to generate 50 terawatt hours (TWh) per year. It was receiving roughly 770 MMcf/d of gas plus some 130,000 b/d of diesel, liquid firing that accelerates wear and lengthens maintenance cycles on turbines designed for gas.[25]The operational dataset in Table 2 shows gas deliveries to power falling from 938 MMcf/d in 2015 to a trough of 452 MMcf/d in 2020, then recovering to roughly 700 MMcf/d in 2024–2025, still less than half of the requirement.[26] Set that 800 MMcf/d shortfall against the approximately 2,000 MMcf/d currently flared within a few hundred kilometers (km) of the starving plants, and the central absurdity of Venezuela's energy economy becomes clear. The country does not lack gas for power but lacks the compression and gathering to connect its own waste stream to its own turbines.

4.3 The loop closes on oil

The final coupling is the least discussed and, for anyone modeling Venezuela's oil recovery, the most consequential. PDVSA's production, processing, and export infrastructure depends substantially on the public grid rather than on dedicated self-generation adequate to its needs. When the grid fails or is rationed, wells shut in, upgraders trip, and export terminals stall, as the 2019 blackouts demonstrated at national scale.[27] Meanwhile the collapse of reinjection (as shown in Table 2) undermines reservoir pressure in precisely the mature fields where associated gas originates. The implication for investors and planners is direct: oil-production scenarios for Venezuela that do not specify a power-sector and gas-midstream recovery path are not scenarios; they are wishes. Chatham House's reconstruction estimates, on the order of $13 billion in priority electricity investment over the first three post-transition years, should be read in this light: not as a competing claim on scarce capital against the hydrocarbon sector but as part of the hydrocarbon sector's own cost curve.[28]

5. Assessment: The unglamorous portfolio comes first

Until September 2026, this argument ran backward: the domestic gas failure was a drag on an oil sector that was not attracting capital. It now runs forward. Roughly 800,000 b/d of new production is under twenty-five-year contract for delivery by the end of the decade, and it is a claim on a gas and power system that cannot adequately serve the 1.2 million b/d Venezuela produces today. It arrives as diluent, as power, and as compression. The Orinoco expansions produce extra-heavy crude that must be blended or upgraded before it moves, and the diluent is light crude from the eastern fields that are gas rich, pressure dependent, and the epicenter of the flaring described above. Upgraders and pumping and export terminals draw on a grid supplying barely 40 percent of nominal capacity. And whatever associated gas the new barrels yield enters the same gathering system, in which more than half the compressor fleet is out of service and the flare is the default disposal route. The compression program below is no longer merely the highest-return investment available in Venezuela; it is a precondition for production growth that has already been financed.

The domestic gas economy fails at three couplings, in ascending order of capital intensity. Gas is wasted because compression is broken. Power is scarce because gas deliveries are half of the required amount and the thermal fleet is degraded. Oil is constrained because power is scarce and reinjection has collapsed. The ordering matters because it defines a sequencing logic that runs opposite to the sector's historical instincts. Venezuela's planners have perennially reached for the prestige greenfield, offshore development, and LNG trains, while the highest-return projects in the country are unglamorous brownfield mechanics: compressors, gathering lines, plant turnarounds, and substation repairs. In a capital-constrained opening, the unglamorous portfolio comes first. Of practical significance is that since March 2026, this portfolio is squarely authorized: US General License 48A explicitly permits US goods, services, and technology for oil, gas, petrochemical, and electricity operations, including maintenance, repair, refurbishment, and spare parts.[29] The legal channel for the highest-value work is already open.

6. Recommendations: Compression before concrete

1. Launch a compression-first emergency program and treat it as the flagship of the opening. An integrated rehabilitation of the Eastern Cryogenic Complex compressor park—engineered against current suction pressures and gas quality rather than original design assumptions, and explicitly incorporating the field personnel who executed a decade of improvised reconfiguration—is the fastest conversion of capital into marketable energy available in Venezuela. It is also the binding constraint on the oil recovery the contracts signed in September 2026 assume. Structure it as investable perimeters, fee-for-service or gas-share contracts over defined gathering and compression systems, rather than as procurement by an insolvent PDVSA Gas. And design the perimeters to reach the associated gas of the oil joint ventures, carrying the monetization rights of Part I, Recommendation 6: a compression contract for gas that nobody owns commercially is a public work, not an investment. Recovered gas will also have more claimants than volume: reinjection to sustain pressure in the light-crude fields that supply Faja diluent, thermal generation, and petrochemical feedstock. Reinjection compression is the most demanding and costly class of the fleet, and the

allocation between it and the grid is a genuine trade-off rather than a sequencing detail. A dispatch hierarchy should be published before the capture program is tendered, not after the molecules exist and the claimants are contesting them.

2. Monetize flare capture with blended finance and honest measurement. Pair commercial flare-capture ventures with methane-abatement finance, conditioned on independent, satellite-verified baselines. Venezuela's flaring intensity makes it the hemisphere's largest cheap abatement pool. Credibility of measurement, not availability of capital, is the binding constraint on accessing climate-linked funds.

3. Ring-fence the gas-to-power payment chain. Give gas deliveries to power priority dispatch and secure them with escrowed collections: a defined share of Corpoelec's gradually recovering revenues and, transitionally, of hydrocarbon export receipts flows through a trustee to gas suppliers before reaching the general treasury. This is the mechanism that converts Part I's hard budget constraint from exhortation into plumbing.

4. Restore PDVSA self-generation and prioritize grid nodes serving oil infrastructure. Decouple the oil system's uptime from the weakest grid segments by rehabilitating dedicated generation at critical upgrading and export facilities, while directing early transmission repairs to corridors serving both population centers and hydrocarbon operations. The GE Vernova program provides the execution vehicle; what it does not provide is fuel, and rehabilitation sequenced ahead of gas supply will deliver capacity that cannot be dispatched.

5. Protect the LPG lifeline while reforming methane prices. Maintain and better target support for household cylinders, the true social contract in Venezuelan gas, in order to create the political space to move industrial methane prices toward cost. Over time, recover NGL export value at José as domestic LPG demand is met more efficiently.

6. Publish the data. A monthly national gas balance covering production, satellite-reconciled flaring, deliveries by sector, and payments performance, published by a revived ENAGAS, would cost almost nothing and would do more for investor confidence than any communiqué. Opacity is currently priced into every Venezuelan gas transaction. Transparency is the cheapest subsidy the state can offer.

The domestic case for gas is now complete: the waste is vast, the fix is cheap, and the payoff propagates from the flare stack to the grid to the wellhead. What the domestic market cannot yet supply is the one thing investment requires: a buyer who pays. Part III finds that buyer offshore.

Notes to Part II

1. PDVSA Gas operational data, 2015–2025; see Table 2.
2. Venezuela's methane venting is equivalent to Colombia's annual natural gas consumption. Palacios, "Venezuela: The Post-Maduro Oil, Gas and Mining Outlook."
3. Table 2 and author's calculations.
4. For sectoral classification, i.e., power generation; steel/aluminum; cement; refining/upgraders; petrochemicals; vehicular CNG; private distributors and industry, see: PDVSA Gas operational data, 2015–2025.
5. Regarding extraction plants, José fractionation trains, 200,000 b/d capacity, LPG's social role, see Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 177–178; Venezuela's pipeline coverage is limited to a corridor, and LPG is the principal residential fuel. "Venezuela Natural Gas Sector."
6. About 90 percent of the population relies on LPG for cooking. Igor Hernández, Francisco J. Monaldi, and Jose la Rosa Reyes, "The Collapse of the Venezuelan Oil Industry: The Role of Above-Ground Risks Limiting FDI," Baker Institute for Public Policy, Rice University, February 2020, https://www.bakerinstitute.org/research/collapse-venezuelan-oil-industry-role-above-ground-risks-limiting-fdi. LPG output is about 20,000 b/d vs. 55,000 b/d demand, and was 105,000 b/d in 2016. Meghan Gordon and Mery Mogollon, "US Treasury Extends Venezuela's LPG Waiver," S&P Global, July 7, 2022, https://www.spglobal.com/energy/en/news-research/latest-news/crude-oil/070722-us-treasury-extends-venezuelas-lpg-waiver-as-calls-grow-for-crude-sanctions-relief. For self-sufficiency until 2009–2010 and US imports until 2019 sanctions, see: "Venezuela Breaks Up LPG Black Market Scheme," Argus, February 16, 2021, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2187417-venezuela-breaks-up-lpg-black-market-scheme.
7. For the José export dock for gas liquids, see: Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 178; author's assessment.
8. More than 50 percent of the Eastern Cryogenic Complex compressor park requires urgent repair or substitution; without compression, "la única solución es quemar y ventear el gas." Ibid., 178–179.
9. For the disproportionate sanctions effect on compression and impracticality of Chinese substitution, see: Ibid., 180
10. For undocumented emergency reconfiguration held in personnel memory, see: Ibid., 180.
11. "Venezuela Gas Pipeline Rupture Slashes Production," Argus, March 22, 2021, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2198264-venezuela-gas-pipeline-rupture-slashes-production.
12. For Muscar handling about 65 percent of national supply; and eastern associated gas cut 78 percent, from about 2.3 Bcf/d to about 500 MMcf/d, see: Mery Mogollon, "Venezuela Gas Complex Blast Hits Heavy Crude Dilution, Power Production: Report," S&P Global, November 18, 2024, https://www.spglobal.com/energy/en/news-research/latest-news/natural-gas/111824-venezuela-gas-complex-blast-hits-heavy-crude-dilution-power-production-report.

13. PDVSA Gas owes payment to producing licensees but does not charge for the gas it delivers; predominantly state-owned consumption removes the incentive to collect a fair price. Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 182. For ministerial price setting under Gas Law Article 12 and IEA-estimated subsidies to domestic gas consumption averaging $1.4 billion per year, 2010–2021, in 2021 dollars, see: Hernández, "Incentivos Económicos, Implementación de Políticas y 'Cuellos de Botella' en la Industria del Gas Natural en Venezuela," 65–68.
14. Venezuela is among the world's ten largest gas flarers in absolute terms; it might rank first on a per-barrel-produced basis. Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 179, citing World Bank Global Gas Flaring Tracker data. The World Bank ranks Venezuela fourth globally on 2025 volumes, behind Russia, Iran, and Iraq. "2026 Global Gas Flaring Tracker Report," World Bank Group, June 23, 2026, https://www.worldbank.org/en/programs/gasflaringreduction/publication/2026-global-gas-flaring-tracker-report.
15. Repairs reduced flaring and venting by about 0.5 Bcf/d. Fontiveros, "El Aprovechamiento del Gas de Quema y Venteo," 179.
16. For GPM decline from the 3.0–4.0 design range to 1.5–2.0 at Punta de Mata and integrated repair-versus-replace optimization, see: Ibid., 179–180.
17. For about 40 percent of about 3 Bcf/d vented or flared, and about $1 billion annual opportunity cost at Henry Hub prices, see: Palacios, "Venezuela: The Post-Maduro Oil, Gas and Mining Outlook." The figure in the text is recalculated from the operational dataset rather than taken from Palacios: 1,994 MMcf/d flared in 2025 (Table 2) is roughly 728 Bcf, or about 755 million MMBtu, a year. Henry Hub averaged $3.42–$3.52 per MMBtu in 2025 and was forecast just under $3.50 for 2026, easing below $3 through the second half. "Short-Term Energy Outlook," US Energy Information Administration, September 2026, https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf. Therefore, $2 billion is the conservative reading of a $2.3–$2.6 billion gross range.
18. Luisa Palacios, Diego Rivera Rivota, and Ira Joseph, "More Efficient Use of Venezuela's Natural Gas Could Strengthen the Region's Energy Security and the Country's Electricity Sector," Center on Global Energy Policy, January 21, 2026, https://www.energypolicy.columbia.edu/more-efficient-use-of-venezuelas-natural-gas-could-strengthen-the-regions-energy-security-and-the-countrys-electricity-sector/.
19. Second NDC pledge: 71 percent cut in venting and flaring by 2030 from 2024 levels; up to half of about 4 Bcf/d output is still flared. "Venezuela Focuses on Gas Flaring in GHG Commitments," Argus, October 30, 2025, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2748068-venezuela-focuses-on-gas-flaring-in-ghg-commitments. Chevron, Eni, and GeoPark together represent some 800,000 b/d of new production by 2030 against current output of about 1.2 million b/d; reliable power is identified as the central near-term bottleneck for oil production growth. On the countervailing production commitments, see: Luisa Palacios, "The US–Venezuela Oil Deal Might De-Risk Oil Company NABEP but not Venezuela," Center on Global Energy Policy, September 9, 2026, https://www.energypolicy.columbia.edu/the-us-venezuela-oil-deal-might-de-risk-oil-company-nabep-but-not-venezuela/. The associated gas increment per barrel from extra-heavy Orinoco production is low, so the constraint is one of demand on the gas and power systems rather than of incremental gas supply. Venezuela's vice minister for gas, Cindy Rondón, told the Venezuela Energética conference on April 27, 2026, that infrastructure recovery needed to be accelerated and projects launched to improve the handling of associated gas. Faulkner, "Eni–Repsol JV Targets Higher Gas Output from Venezuela's Cardon IV Field."
20. Christopher Sabatini and Walt Patterson, "Reforming Venezuela's Electricity Sector: Options and Priorities for Rebuilding a Collapsed System," Chatham House, December 2021, https://www.chathamhouse.org/2021/12/reforming-venezuelas-electricity-sector; "Venezuela Power Sector."
21. For installed about 36 GW, available about 10.5 GW in 2019, disproportionate thermal decline, 2019 national blackout, and consequences, see: Sabatini and Patterson, "Reforming Venezuela's Electricity Sector," 8–9.
22. For steam-plant energy availability 30 percent in 2013, 12.88 percent in 2016, and abandonment of maintenance routines, see: "Informe Final," Asamblea Nacional de Venezuela, Comisión Mixta para el Estudio de la Crisis Eléctrica en el País, January 15, 2017, paragraphs 174–175, https://www.ariae.org/servicio-documental/comision-mixta-para-el-estudio-de-la-crisis-electrica-en-el-pais-informe-final.
23. For Guri overexploitation beyond firm energy, and 2010 and 2016 crises, see: Ibid., paragraphs 176–179. For drought exposure and climate vulnerability, see: Sabatini and Patterson, "Reforming Venezuela's Electricity Sector."
24. For 765 kV network plus 7.8 percent, 1998–2014, see: "Informe Final," paragraphs 180–181. For 2019 blackout propagation, see: Sabatini and Patterson, "Reforming Venezuela's Electricity Sector." GE Vernova will bring 1 GW online within twenty-four months and 5 GW over the following four years, covering thermal and hydroelectric generation, transmission and distribution, and key substations, building on a June 15, 2026 cooperation agreement with Corpoelec. On the rehabilitation program, see: "Fact Sheet: Delivering on President Trump's Promise to Unleash Prosperity and Security for the United States and Venezuela," US Department of Energy, September 2, 2026, https://www.energy.gov/articles/fact-sheet-delivering-president-trumps-promise-unleash-prosperity-and-security-united.
25. For the thermal park requirement of more than 1,500 MMcf/d for 50 TWh/yr, actual gas about 770 MMcf/d plus about 130,000 b/d diesel, and liquid firing raising maintenance cycles and unavailability, see: "Informe Final," paragraphs 208–210.
26. PDVSA Gas operational data, 2015–2025, power-generation series.
27. For the 2019 blackout disrupting oil production, see: Sabatini and Patterson, "Reforming Venezuela's Electricity Sector," 9. For PDVSA reliance on grid power absent adequate self-generation, see: author interview with Rubén Pérez and industry accounts; "Venezuela Upheaval Could Crack Open Power Sector," Argus, January 9, 2026, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2774174-venezuela-upheaval-could-crack-open-power-sector.
28. For reconstruction cost estimates drawing on Inter-American Development Bank scenarios, about $13 billion over the first three years: Sabatini and Patterson, "Reforming Venezuela's Electricity Sector."
29. US Department of the Treasury, Office of Foreign Assets Control, Venezuela General License 48A (March 13, 2026), as summarized in: "Consolidated Chart of Venezuela General Licenses"; Christopher Boyd, et al., "Summary of Recent OFAC Licenses Impacting Key Venezuela Sectors," Herbert Smith Freehills Kramer, April 1, 2026, https://www.jdsupra.com/legalnews/summary-of-recent-ofac-licenses-3137102/.

Part III. The export window: Trinidad, Colombia, and the competition for capital

1. Thirty-five years of announcements

For thirty-five years Venezuela has announced gas export projects and delivered none. The record opens in 1990, when PDVSA selected Shell, Exxon, and Mitsubishi for the Cristóbal Colón LNG project over Dragon, Patao, Mejillones, and Río Caribe, the same four fields now under negotiation. That venture reached a preliminary development agreement in 1991, incorporated as Sucre Gas in 1994, stalled on LNG economics in 1996, and was revived in downsized form as PVLNG in 2000. LNG trains at Gran Mariscal, Deltana, and Blanquilla–Tortuga were designed and memoranda were signed with partners from Houston to Tehran. But the country that borders the Atlantic Basin's most liquid gas market remains, in 2026, an exporter of nothing but promises and, since March 2026, a few truckloads of donated LPG across the Colombian border.[1]

This installment examines whether the post-January 2026 opening changes that record: through which projects, on what economics, and against what competition. The propositions now on the table differ in kind from those of the 2000s. They are brownfield tie-backs into infrastructure that already exists and is underused, held by counterparties whose own supply is declining, with pipelines laid, platforms installed, and liquefaction and petrochemical capacity built and running below nameplate. That configuration asks comparatively little of Venezuela, which is what makes it viable in a competitive market for gas capital. The constraint sits elsewhere, in the instruments. Through 2026, the gas sector has accumulated licenses, memoranda, and work plans, while the oil sector has signed contracts with published fiscal terms. That distinction organizes what follows.

2. What January 2026 changed

Three shifts define the new environment and their conjunction—rather than any one of them—constitutes the window.

The political-legal shift: The United States' removal of Maduro on January 3, 2026, was followed within weeks by two structural moves. In Caracas, a partial reform of the Organic Hydrocarbons Law at the end of January opened a 180-day renegotiation of existing joint ventures, moved royalty and tax terms toward a negotiable and more progressive structure (a headline royalty of 30 percent against a reduced income-tax burden), and simplified the accretion of special petroleum taxes. The reform's perimeter deserves precision: it governs crude oil and associated gas, and it leaves the 1999 Gas Law intact with counsel summaries explicit that nothing changed in the legislation governing non-associated gas (Part I, notes 10 and 12). Every export proposition examined below therefore sits outside both the reform and the renegotiation it triggered.[2] In Washington, a lattice of Office of Foreign Assets Control (OFAC) general licenses reopened the oil, gas, petrochemical, and electricity sectors to US persons under conditions: US-law contracts, US dispute resolution, payments to blocked persons routed through designated Treasury accounts, and exclusion of Russian, Iranian, and Chinese participation. General License (GL) 50A authorizes full oil and gas operations for six named majors (BP, Chevron, Eni, Maurel & Prom, Repsol, and Shell), GL 48A opens the services and equipment channel, and GL 49A permits negotiation of contingent contracts for new investment.[3] A comprehensive waiver of PDVSA sanctions followed on March 18, excluding Citgo-related transfers and dealings touching Russia, Iran, China, Cuba, or North Korea, with additional licenses in April covering contract negotiation and financial services. Interim leader Delcy Rodríguez signed the consolidated oil and gas reform framework on July 8.[4]

The corporate shift: The companies moved within nine weeks of the rupture and continued through the year. Shell signed agreements on March 5 spanning offshore gas and onshore oil, clearing the path for Dragon and adding technical accords with Venezuelan and US service firms.[5] Venezuela signed a tripartite agreement with Eni and Repsol on Cardón IV on March 13, restoring crude-for-gas debt settlement and framing an expansion of Perla for domestic supply first and exports later.[6] By April, Shell was in advanced talks over the three remaining Mariscal Sucre fields and Loran, and Chevron had formalized a swap returning its Loran-area licenses to the state against heavy-oil acreage.[7] On June 11, Venezuela granted Shell the license for Loran Phase 1, together with service orders over the onshore Monagas fields and instruments addressing the use of flared gas, the first commercial instruments of the opening to reach the waste described in Part II.[8] In July, Shell opened tendering for Dragon drilling services with four wells from the second quarter of 2027, with the contract award expected by the end of September and its execution conditional on an investment decision not yet taken.[9] On August 13, the Loran Phase 2 license was awarded to a consortium of BP, XRG, and UCC.[10]

The market shift: Demand-side urgency exists on both flanks. To the east, Trinidad's production decline has left the 12 mtpa Atlantic LNG complex shipping roughly 9 mtpa, forced BP to decommission the long-idled Train 1, and pushed ammonia and methanol plants to shut or idle; Trinidadian demand at full operation exceeds 3 Bcf/d.[11] To the west, Colombia lost gas self-sufficiency in December 2024 and now imports LNG at prices that have become a domestic political issue, with production down roughly 20 percent since 2019 against firm power-sector demand.[12] Venezuela sits between two gas-short neighbors holding, respectively, spare liquefaction and an idle cross-border pipeline.

What has not changed: Three qualifications bound the optimism. The general licenses are self-executing but conditional and revocable, a design that restores US engagement while retaining leverage; Section 5 treats their duration as the binding constraint. The Venezuelan legal foundation is contested: former officials have called the January reform unconstitutional and Washington has not recognized the legitimacy of the National Assembly that passed it, so instruments signed today carry successor government risk on both sides.[13] And no gas project has reached an FID.

The asymmetry with oil is measurable. During a September visit to Caracas by the US secretary of energy, Eni migrated Junín 5 into a twenty-five-year production participation contract, GeoPark signed a comparable contract over Bare, Chevron settled revised joint-venture terms and took additional Orinoco acreage against more than $7 billion of investment over five years, and GE Vernova contracted to rebuild 6 GW of power capacity. Separately, and more contentiously, Washington and the interim authorities announced an arrangement assigning seventeen fields to a single private operator on terms the two governments described differently and that analysts have questioned on grounds of transparency, legality, and legitimacy (Part I, Box 2 and note 35). Chevron's chief executive attributed the commitment to the reformed fiscal terms, which on his account moved Venezuela from uncompetitive within the company's global options to competitive against them.[14] The gas sector's 2026 record contains no instrument of that kind. Oil received contracts, while gas received permission. The difference is not presentational: a license confers the right to develop, while a contract fixes the fiscal and commercial terms on which development is financed.

3. The export propositions examined

Table 3 summarizes the realistic options; the geography behind them appears in Figure 2 of Part II.

3.1. Trinidad: The tie-back logic

Dragon asks less of Venezuela than any gas project in the country's recent history. The field is delineated at 4.2 Tcf. It lies 16–18 kilometers from Shell's Hibiscus platform and the pipeline system feeding Atlantic LNG, whose capacity is being upgraded from 700 MMcf/d toward 1 Bcf/d. It requires no Venezuelan onshore infrastructure and involves no PDVSA equity: the thirty-year license granted in December 2023 runs

Table 3. Venezuela's natural gas export options: Routes, anchor projects, timing, and principal risks

Route	Anchor projects and scale	Timing and indicative value	Principal risks
Trinidad (pipeline to Atlantic LNG and petrochemicals)	Dragon (4.2 Tcf; Shell 70 percent as operator and NGC 30 percent; thirty-year license, December 2023) with a 16–18 km tie-back to Hibiscus. Follow-ons: Loran (7.3 Tcf Venezuelan side; Phase 1 licensed to Shell, June 2026; Phase 2, about 4 Tcf recoverable, to BP as operator with XRG and UCC in equal interests, August 2026, both phases in parallel); Patao–Mejillones–Río Caribe (Mariscal Sucre, about 12 Tcf across the four fields); Cocuina–Manakin (about 1 Tcf, BP and NGC; BP sold 20 percent to NGC in 2026). A 15–20 Tcf cross-border province.	Dragon drilling from the second quarter (Q2) of 2027; FID possible by the end of 2026 and first gas in 2029. Initial about 185 MMcf/d ramping toward 350 MMcf/d; about $500 million per year to Venezuela on CGEP estimates, on LNG-linked netbacks. Manatee (Trinidad side) onstream late 2027 at about 600 MMcf/d. Atlantic LNG restorable to 12 mtpa by about 2030 (about 6 mtpa incremental). Pipeline upgrade from 700 MMcf/d to 1 Bcf/d under way; minimal onshore build.	FID discipline; license duration against a thirty-year asset life (five reversals, 2023–2026); residual Russian claims at Patao–Mejillones; the Venezuela–Trinidad fiscal split.
Colombia (Antonio Ricaurte pipeline)	Cardón IV expansion toward its 1.2 Bcf/d nameplate; about 0.5 Bcf/d exportable above domestic commitments; rehabilitation and reversal of the existing 224 km line (built in 2007; 500 MMcf/d capacity; flowed from Colombia to Venezuela 2009–2015 and idle since).	Repairs estimated at $30 million over up to two years under the March 2026 roadmap; exports plausible by 2028, contingent on works and licensing. About $700–$800 million per year at benchmark-linked prices.	Colombian counterparty and regulatory constraints (Ecopetrol investment-control rules; reinstatement of the environmental license); sanctions clarity for repairs; competing domestic calls on Perla gas.
LPG and NGL trade (trucks and ships from José)	Recovered liquids chain. Scalable with fractionation recovery. Largely existing infrastructure (José dock).	Begun at token scale (first LPG trucks to Colombia in March 2026, as a donation). Modest indicative value initially; high margin per unit.	Domestic LPG priority; pace of processing recovery.
Greenfield Venezuelan LNG	Multi-billion-dollar liquefaction required.	Not before the 2030s.	Uncompetitive against sunk-cost alternatives in a well-supplied market this decade.

Sources: Notes 5–28; author's assessment.

to Shell as operator with 70 percent and Trinidad's NGC with 30.[15] Like every proposition in Table 3, it is a non-associated license under the Gas Law, and therefore outside the oil law renegotiation now occupying the joint ventures. Trinidad's government has stated the intended split: roughly 70 percent of Dragon gas to Atlantic LNG, 30 percent to petrochemicals.[16] On Shell's planned volumes, an initial phase near 185 MMcf/d ramping toward 350 MMcf/d, the Center on Global Energy Policy puts Venezuelan revenues conservatively at about $500 million a year, earned on export-linked netbacks outside the domestic price regime.[17]

The timing has slipped. First gas has moved from the 2026–2027 discussed in 2025 to 2029 on current drilling schedules, and the investment decision, possible by the end of 2026, remains contingent on US license terms whose horizons are short relative to a thirty-year asset. The nearer milestone is the drilling services award expected by the end of September 2026, which will contract rigs against a decision not yet taken.[18]

The follow-on volumes are larger than Dragon. Shell was reported in April to be pursuing as much as 20 Tcf: the three remaining Mariscal Sucre fields (Patao, Mejillones, and Río Caribe, the four-field project totaling some 12 Tcf) plus the 7.3 Tcf Venezuelan Loran side of the unitized Loran–Manatee accumulation.[19] Loran carries the greater weight. Shell took an investment decision on Trinidad's 2.7 Tcf Manatee portion in July 2024, with first gas expected in late 2027 at around 600 MMcf/d, by itself some 45 percent of the feed gas Atlantic LNG needed to sustain its 2025 output. The concept for the Venezuelan side is subsea wells on Loran tied back to the Manatee platform, producing the unitized field as a single system.[20]

Three steps in 2026 cleared the way. In April, Chevron formalized an asset swap returning its 60 percent interest in Plataforma Deltana Block 2, which contains Loran, together with Block 3 and a minority oil interest, against additional heavy-oil working interests and the Ayacucho 8 development rights; Venezuela recovered its most valuable dormant gas license by paying in oil acreage.[21] On June 11, Loran Phase 1 was licensed to Shell, which already operates Manatee on the Trinidadian side. On August 13, Phase 2—about 4 Tcf of recoverable gas to be developed in parallel with Phase 1—was licensed to BP as operator alongside XRG, the international investment arm of Abu Dhabi's ADNOC, and UCC Oil and Gas Holding of Qatar, with equal working interests. BP separately signed a memorandum regarding the Carúpano East block in the Mariscal Sucre area and sold 20 percent of its Cocuina–Manakin interest to NGC.[22] What has not cleared is the residual Russian-held license claim over Patao and Mejillones, the legacy of Rosneft's 2017 export-rights license and its sanctions-forced 2020 transfer to Roszarubezhneft, which Caracas will need to extinguish before Shell's largest follow-on can proceed.[23]

Two features of the Loran awards carry more information than the acreage. Neither phase includes state equity, repeating the Dragon structure. And Phase 2 reached its holders by transfer of PDVSA Gas's own interest in the license, subject to regulatory approval, which removes the state from a commercial position it previously held. Read against Part I, the pattern is consistent: the projects that advance are those structured to keep PDVSA Gas's balance sheet out of the revenue line.

Assembled, these assets constitute a cross-border province rather than a set of projects, on the order of 15–20 Tcf of largely delineated resource within tie-back distance of Trinidad's underused processing, liquefaction, and petrochemical complex. Developed in sequence, based on Center for Strategic and International Studies (CSIS) estimates, they could return Atlantic LNG to its full 12 mtpa by or before 2030, roughly 6 mtpa above 2025 volumes and potentially including a restart of the mothballed Train 1, arriving as the European Union completes its planned cessation of Russian gas imports and looks to diversify a portfolio in which US cargoes already supply more than half of its LNG.[24] Venezuela would obtain access to the LNG market without financing a liquefaction train.

The route's own history identifies what has bound the sector, and it is neither geology nor demand. Box 4 sets out the chronology.

3.2. Colombia: The pipeline that already exists

The western route is smaller and further advanced politically. The 224 km Antonio Ricaurte pipeline was built in 2007 so that flows could eventually reverse toward Colombia; they never did, and the line has stood idle since 2015.[26] Its nameplate capacity of 500 MMcf/d corresponds closely to the volume the Columbia University Center on Global Energy Policy identifies as exportable: expanding Cardón IV toward its 1.2 Bcf/d design capacity could support some 0.5 Bcf/d of exports, worth $700–$800 million a year to Venezuela at benchmark-linked prices, while improving Colombia's supply security.[27]

The works required are modest against that revenue. In March, Colombia's mining, energy, and environmental authorities agreed to a roadmap with PDVSA's Colombian unit. PDVSA would execute repairs along the pipeline's original route, beginning with a damaged 5 km section on the Colombian side, while Colombia reactivated the environmental license dormant since 2019. The rehabilitation is estimated at roughly $30 million over two years. Ecopetrol has signaled interest conditional on US licensing clarity, and Colombian officials remain candid that financing and Ecopetrol's investment-control rules are unresolved.[28] Thirty million dollars of civil works, less than 5 percent of a single year's gross export value, stand between an idle line and several hundred million dollars in annual gas trade.

The upstream side has moved in parallel. The March tripartite agreement was followed in April by an extension of the Cardón IV license from 2036 to 2051 with an explicit export pathway, which indicates that Perla's expansion is being underwritten on export economics rather than on PDVSA Gas receivables. The partners now frame the block around some 20 Tcf of technically recoverable resources, less than 10 percent of what is produced, with ambitions to roughly double output.[29]

Box 4. The license whipsaw: Five reversals in three years

Between January 2023 and March 2026, the US authorizations for the Dragon and Cocuina–Manakin projects were granted (January 2023); amended and extended (October 2023); revoked outright (April 2025, with winddown by May); re-granted on restrictive three-phase terms (October 2025, with a negotiation window and mandated US-company involvement); and finally broadened under the 2026 general licenses. On the Venezuelan side, Maduro suspended Dragon in October 2025 amid the escalation that preceded his fall.[25]

That is five reversals in three years on a project whose geology, engineering, and commercial logic did not change. Since 2023, the operative constraint on Venezuelan gas exports has been the duration of the authorization rather than the reservoir or the counterparty, and investment decisions on thirty-year assets are not taken against authorizations that turn over faster than a drilling campaign.

What is public, however, is a work plan rather than a contract. The project manager told the Venezuela Energética conference in April that the first step is a ramp from about 580 to 645 MMcf/d, followed by additional drilling and infrastructure upgrades, with no date attached. The partners describe a sustainability agreement providing for expanded production, higher domestic volumes, and conditions for future exports, but publish neither those conditions nor the export threshold.[30] The commercial intent is evident; the term that would make the expansion financeable is not on the record. Meanwhile, the first LPG trucks have crossed the Simón Bolívar Bridge. The open question is sequencing because the same Perla molecules are claimed by domestic power generation, and Section 4 addresses it.

3.3 What this means for hemispheric gas markets

At full build-out over the early 2030s, with the cross-border province restoring Atlantic LNG toward nameplate and half a Bcf/d flowing westward, Venezuela would remain a modest supplier in global terms: an incremental 6 mtpa is on the order of 6 percent of European Union (EU) 2025 LNG demand. The regional effects are larger. They include extending the commercial life of the Caribbean's only liquefaction complex, displacing high-cost LNG imports in Colombia, offering Europe a short-haul Atlantic supply free of major chokepoints that diversifies a portfolio concentrated in US cargoes, and adding supply diversity to a basin otherwise converging on Gulf Coast molecules.[31] For US policy, the objectives align unusually well: exports through these routes strengthen allied energy security, substitute for extra-hemispheric suppliers, monetize methane that would otherwise be vented, and generate export receivables available to collateralize arrears settlement and domestic reform.

4. Exports as solvent: What the export circuit can and cannot fix

The case for prioritizing exports is structural rather than fiscal, and it connects this installment to Part I. The pathologies diagnosed there follow from producers' captivity to a single insolvent buyer at administered prices. Export projects create offtake counterparties—among them Atlantic LNG offtakers, Ecopetrol, and Trinidadian petrochemical buyers—whose creditworthiness does not depend on the Venezuelan treasury and whose prices no Venezuelan ministry sets.

The limits of that proposition warrant equal precision. Nothing announced in 2026 changed who buys gas for the domestic market, at what price, or on whose credit. PDVSA Gas's transfer of its Loran interest confirms that the export circuit is being built outside the domestic commercial chain, not that the chain is being reformed. The monopsony is an offtake structure sitting downstream of the separator and the export circuit is being routed around it. The domestic recommendations of Part I therefore remain both necessary and unaddressed.

What exports introduce is a price reference. Once a producer holds an export netback, the domestic market competes for the same molecules and the cost of an administered price becomes quantifiable. As described in Part I, Egypt's sequence ran the same way in reverse: domestic price reform became executable once export parity made the subsidy measurable (Part I, notes 33 and 34). The concern that exports divert gas from Venezuelan consumers inverts the observed mechanism because under the monopsony gas remained in the country and was flared, while under export pricing volumes are produced that can serve both markets.

The sequencing objection of domestic market first and exports later meets the same difficulty. Fixing the domestic market requires investment, and investment requires a creditworthy revenue anchor that the domestic market does not yet provide. Export-anchored projects fund drilling, compression, and arrears settlement from external revenue while domestic reform proceeds on a slower track. The operative model for 2026–2032 is a dual-circuit gas economy: an export circuit at international netbacks financing recovery, and a domestic circuit converging gradually toward cost as ministerial pricing is replaced in stages.

5. The competition for capital

Venezuelan gas competes for allocation against US Gulf Coast liquefaction with investment-grade offtakers and no country risk, against Qatari brownfield trains at the bottom of the global cost curve, and against Argentina's Vaca Muerta. Three screens govern that allocation and Venezuela performs differently on each.

Cost against a well-supplied market comes first. The United States sanctioned roughly 65 mtpa of new liquefaction in 2025. In December of that year, Energy Transfer suspended development of the 16.5 mtpa Lake Charles project, reallocating capital to pipelines with superior risk-adjusted returns, a decision read against expectations of LNG oversupply in the late 2020s and early 2030s, the window in which Venezuelan volumes would arrive.[32] The consequence for Venezuela divides. Greenfield Venezuelan liquefaction does not clear a hurdle rate in that market against alternatives whose costs are already sunk, which is why Table 3 places arrival in the 2030s at the earliest. Tie-backs into Trinidad's existing trains face the opposite arithmetic because they add molecules to liquefaction that has already been paid for.

Time to monetization comes second, and here the cross-border province ranks well: delineated reservoirs, tie-backs of 16–20 km, installed platforms, and processing capacity awaiting feed. Manatee's start-up on the Trinidadian side in late 2027 provides a benchmark for the interval between decision and cash flow in these waters under stable licensing.

The duration of permission comes third and is where Venezuela ranks last in its peer set. No other jurisdiction in that set carries a five-reversal license record on a single project (Box 4). It is also the screen over which Caracas has the least control and Washington the most.

The composition of the capital committed so far is consistent with the first two screens and silent on the third. BP, Shell, Eni, Repsol, ADNOC's international investment arm XRG, and UCC Oil and Gas Holding—the oil and gas business of a private Doha industrial group whose core trade is power and infrastructure construction—all took positions during 2026. XRG characterized its entry as investment in advantaged resources with access to established infrastructure and clear routes to market.[33] Gulf capital therefore appears in this account in two unrelated capacities. QatarEnergy's state LNG business sets the cost benchmark against which Venezuelan volumes are measured, while Gulf diversification capital holds working interests in the province: different balance sheets take different decisions. Neither resolves the licensing question, and partners whose funding is independent of Caracas are also the partners best able to postpone.

Near-term Atlantic balances are tighter than the supply build implies. Missile strikes on Ras Laffan in March 2026 removed 12.8 mtpa, some 17 percent of Qatar's export capacity, for a repair period QatarEnergy put at three to five years.[34] They also prompted long-term force majeure on contracts to buyers in Europe and Asia. The disruption widens the space for Atlantic supply in the second half of the decade without altering Qatar's underlying cost position.

Scale sets the final constraint. Venezuela's full-sector recovery requirement is estimated at $10–$12 billion a year and more than $110 billion in total, nearly all of it from foreign balance sheets that have alternatives.[35] Venezuelan gas earns portfolio space where delineated resource, short tie-back distances, and adjacent buyers with declining supply outweigh political and licensing risk that no peer in the set carries, a test met today by perhaps four or five projects. The margin is time limited. Trinidad's industrial base cannot wait past this decade for feed gas, Colombia contracts long-term LNG as a hedge with each quarter of uncertainty, and the technical teams assembled for Venezuela in 2026 are redeployable. Windows of this kind close through the reallocation of people and capital rather than through announcements.

6. Recommendations: From licenses to contracts

For Venezuelan policymakers

1. Sequence Dragon ahead of the other gas decisions. Resolving the outstanding fiscal and administrative points in 2026 or 2027 would establish a reference for every subsequent negotiation. Terms conceded on a 4.2 Tcf field are recoverable across the 12 Tcf of Mariscal Sucre volumes that would follow, and a license that produces no investment decision produces no revenue.

2. Define the domestic supply obligation as a quantity. In the Cardón IV expansion and in new licenses, a fixed and published volume at a stated price, with incremental volumes free for export at market netbacks, would replace the domestic-market-satisfaction clause that has left export rights indeterminate since the 2000s. The point is financial rather than one of drafting: lenders price an open-ended domestic call as an unquantifiable interruption risk. A bounded first call is financeable at most levels; an undefined one is financeable at none.

3. Apply export receivables to the reform balance sheet. Defined shares of export revenue, held through trustee structures, can fund producer arrears settlement, the compression program of Part II, and the gas-to-power escrow.

For US policymakers

4. Extend the licensing horizon. Multiyear general licenses with a published renewal standard, together with a stated successor facts policy protecting contracts executed in good faith, address the constraint identified in Section 5. The present framework has brought companies to the table; the record of 2026 is that it has not brought them to an investment decision in gas.

5. Treat the interconnections as energy security infrastructure. Support for the Trinidad and Colombia links, including licensing clarity for pipeline rehabilitation on the western route, serves stated objectives on Caribbean stability, methane abatement, and the displacement of extra-hemispheric suppliers. On the western route, the instrument required is a permission rather than an appropriation because the works are costed in tens of millions of dollars and are to be executed by the parties themselves.

For investors and operators

6. Screen on the template rather than the jurisdiction. The Venezuelan gas positions that clear a competitive hurdle rate share five characteristics: delineated resource, short tie-back, export-anchored or export-linked offtake, a US-law contract under the general licenses, and no dependence on PDVSA Gas's balance sheet. Dragon and the remaining Mariscal Sucre fields, the Cardón IV expansion, the unitized cross-border fields, and flare-capture perimeters with export or power offtake meet that test. Positions whose revenue line runs through the domestic administered price system do not, pending the reforms set out in Part I.

The endowment has not been the binding constraint on Venezuela's gas sector at any point in the period this paper examines, and it is not the constraint now. What the 2026 opening has supplied is capital with alternatives, neighboring buyers with declining supply, and a licensing framework that permits transactions while limiting their duration. What it has not yet supplied in gas is the instrument on which a thirty-year development is financed. That gap, rather than the resource base or the statute, is what the coming twenty-four months will settle.

Notes to Part III

1. "Evolution of Venezuela's Natural Gas Regulatory Framework, 1990–2026," sections 5.2–5.3. For Venezuela currently exporting no natural gas, see: "Venezuela—Oil & Gas Laws and Regulations 2026," International Comparative Legal Guides, February 6, 2026, https://iclg.com/practice-areas/oil-and-gas-laws-and-regulations/venezuela/. For the first LPG truck exports on March 13, 2026, see: Silvana Solano Rodriguez, "Venezuela and Colombia Advance Bilateral Agenda on Trade, Energy, and Security," Venezuelanalysis, March 16, 2026, https://venezuelanalysis.com/news/venezuela-and-colombia-advance-bilateral-agenda-on-trade-energy-and-security/. The March 2026 shipment was characterized by the Venezuelan government as an initial donation by PDVSA rather than a commercial sale, at roughly 900,000 liters a day, and was the first binational hydrocarbon movement since the Antonio Ricaurte pipeline ceased operating in 2015. Anabela Gonzalez, "Delcy Rodríguez Anuncia que Venezuela Exportará Gas Licuado a Colombia en 'un Gesto de Buena Voluntad,'" CNN en Español, March 13, 2026. https://cnnespanol.cnn.com/2026/03/13/venezuela/delcy-rodriguez-exportacion-gas-licuado-colombia-orix; "Venezuela Picks Three Firms for LNG Project," *Oil & Gas Journal*, July 2, 1990, https://www.ogj.com/pipelines-transportation/lng/article/17214597/venezuela-picks-three-firms-for-lng-project. For 13.9 Tcf across Dragon, Patao, Mejillones and Río Caribe, see: R. Prieto, I. Van Der Molen, and R. Ramírez de Arellano, "Geologic Setting and Gas Reserves of the Venezuelan LNG Project," American Association of Petroleum Geologists, February 1, 1993, https://www.osti.gov/biblio/6060882.
2. For the January 3, 2026 ouster, the structured and conditional reopening, and the April 1, 2026, delisting of Delcy Rodríguez, see: Margaret B. Beasley, Seth D. DuCharme, and Bryan W. McCracken, "Navigating Investment in Venezuela: A Real-Time Consolidated Guide to Current OFAC Licenses," Bracewell LLP, last visited October 13, 2026, https://www.bracewell.com/knowledge-hub/navigating-investment-in-venezuela/; January hydrocarbons-law reform. For the180-day joint-venture review, 30 percent royalty with reduced income-tax burden, and shift from regressive terms, see: Francisco Monaldi and Wood Mackenzie analysts, remarks at AAPG webinar on Venezuela, 2026 (transcript on file with author). On the reform's perimeter and the survival of the 1999 Gas Law, see Part I, notes 10 and 12.
3. For GL 46B, 47, 48A, 49A, 50A, and their conditions, see: Beasley, et al., "Navigating Investment in Venezuela: A Real-Time Consolidated Guide to Current OFAC Licenses."; Boyd, et al., "Summary of Recent OFAC Licenses Impacting Key Venezuela Sectors." GL 50A was issued on February 13, 2026, and amended on February 18.
4. "US Waives Sanctions on Deals Involving Venezuela's PDVSA," Reuters, March 18, 2026, https://www.yahoo.com/news/articles/us-waives-sanctions-deals-involving-140413276.html; OFAC recent actions, GLs 56–57 (April 14, 2026); "Venezuela's Rodriguez Signs Oil and Gas Reform Framework," Reuters, July 8, 2026, https://www.reuters.com/business/energy/venezuelas-rodriguez-signs-oil-gas-reform-framework-2026-07-08/.
5. For offshore gas and onshore oil agreements, see: Carito and Pirital. "Shell Signs Oil and Gas Exploration Agreements with Venezuela," Reuters, March 5, 2026, https://www.reuters.com/business/energy/venezuelan-govt-shell-sign-oil-deals-state-television-says-2026-03-05/.
6. "Venezuela Signs Deal with Eni and Repsol to Boost Gas Production," ANSA, March 13, 2026, https://www.ansa.it/english/news/business/2026/03/13/venezuela-signs-deal-with-eni-and-repsol-to-boost-gas-production_93adbcbd-0ad2-46fd-bbee-d1326677f995.html. For Perla as about 580 MMcf/d, about 33 percent of national gas consumption, and restored crude-for-gas settlement, see: Esteller, "Repsol y ENI Apuestan por el Gas Venezolano con un Nuevo Acuerdo para Explotar su Principal Activo en el País."
7. Shell was in advanced talks over four areas with 20 Tcf combined; Chevron was expected to relinquish the Loran-area stakes, which would be re-offered. Williams and Parraga, "Shell in Advanced Talks with Venezuela for More Gas Areas, Sources Say." For talks on Patao, Mejillones, and Río Caribe, see: Silvana Solano Rodriguez, "Shell Moves to Expand Venezuela Natural Gas Operations," Venezuel analysis, April 8, 2026, https://venezuelanalysis.com/news/shell-moves-to-expand-venezuela-natural-gas-operations/. Venezuela receives Chevron's 60 percent operated interest in Plataforma Deltana Block 2, which contains the Loran discovery, its 100 percent interest in Block 3, containing Macuira, and a 25.2 percent non-operated interest in Petroindependiente. Chevron receiving an additional 13.21 percent in Petroindependencia, taking it to 49 percent, and Ayacucho 8 development rights for Petropiar. On the swap itself, see: "Chevron Consolidates Venezuela Heavy Oil Position in Asset Swap," Chevron, press release, April 13, 2026, https://www.chevron.com/newsroom/2026/q2/chevron-consolidates-venezuela-heavy-oil-position-in-asset-swap.
8. For Phase 1 license signed at Miraflores, five instruments including the first service and purchase orders under the March technical-financial alliance, agreements over the Carito and Pirital production units in Monagas, and seven reservoirs of which six are transboundary, see: "Venezuela Hands Shell a License for the Cross-Border Loran Gas Field Shared with Trinidad," MercoPress, June 11, 2026, https://en-.mercopress.com/2026/06/11/venezuela-hands-shell-a-license-for-the-cross-border-loran-gas-field-shared-with-trinidad. For instruments addressing the use of flared gas, subsea tie-back to Hibiscus, and FID possible before end-2026, see: Antonio Zavarce, "Shell Loran: License for 7 TCF of Offshore Gas," Inspenet, June 15, 2026, https://inspenet.com/en/news/shell-loran-license-for-7-tcf-of-offshore-gas/.

For Loran 7.0–7.5 Tcf, Manatee 2.6–2.7 Tcf, and award following the Chevron relinquishment, see: "Non-Associated Gas Licence for Loran Gas Field," Ocean Energy Resources, June 14, 2026, https://ocean-energyresources.com/2026/06/14/non-associated-gas-licence-for-loran-gas-field/.

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the Country's Electricity Sector." For the 18 km figure, see: Williams, "Shell Aims to Bring Gas from Venezuela to Trinidad in 2026, Sources Say." The range is given here rather than a single figure.

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