

An offshore oil rig is silhouetted against a sunset sky. The rig's complex lattice structure is prominent, with several tall derrick-like towers. The sun is low on the horizon, casting a warm orange glow on the water and the rig's base. The overall scene is industrial and atmospheric.

Venezuela's Oil Industry: Current Challenges and Future Opportunities

A strategic outlook for upstream investors, operators, and market entrants

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By Plata Energy LLC, Houston, TX

Executive Summary

The Partial Reform of the Organic Hydrocarbons Law (LOH) in January 2026 changed the legal, fiscal, and operational structure of Venezuela's oil industry, and Venezuela is re-emerging as one of the most consequential upstream reopening stories in the Western Hemisphere.

The essence of this reform is a remarkable improvement and simplification of the fiscal terms and the contractual terms. On a macro level, the reform signals a reconfiguration of the power structure of the local hydrocarbon industry, with PDVSA shifting from dominant sovereign operator to a role akin to that of a hydrocarbon agency of application, thus transferring operational control. Private companies are permitted to participate directly in primary operations and commercial activities, either by forming joint ventures (where the Venezuelan state holds a majority stake) or through fully private operation contracts made with PDVSA and/or Joint Ventures.

The new framework focuses on economic viability and allows private operators to manage production and sales facilities, substantially improving project economics and expanding the range of contractual structures available to investors. The legal amendments have introduced a more stable and globally competitive fiscal framework, replacing the previous government take, which often exceeded 90%, with a flexible structure. Under the new regime, the government take is estimated at approximately 75% under the law's maximum parameters and can be reduced to a range of 60%–50% depending on the established development plan.

The investment case rests on two complementary pathways. Brownfield rehabilitation can restore shut-in production and generate relatively rapid cash flow from suboptimal existing assets and infrastructure, while greenfield developments—particularly in the Orinoco Belt and selected offshore gas projects—offer scalable long-term reserve and production growth. In both cases, value creation will depend less on resource access than on technical execution, logistics, uptime, and disciplined CAPEX and OPEX management.

For prospective entrants, the strategic implication is clear: Venezuela now offers a genuine first-mover opportunity, but not a low-effort one. Implementing robust CAPEX and OPEX frameworks from the initial stages enables structured and predictable operations. Integrating these expenditures within negotiated Development Plans ensures alignment with production objectives and promotes optimal capital return timeframes in an efficient operational environment.

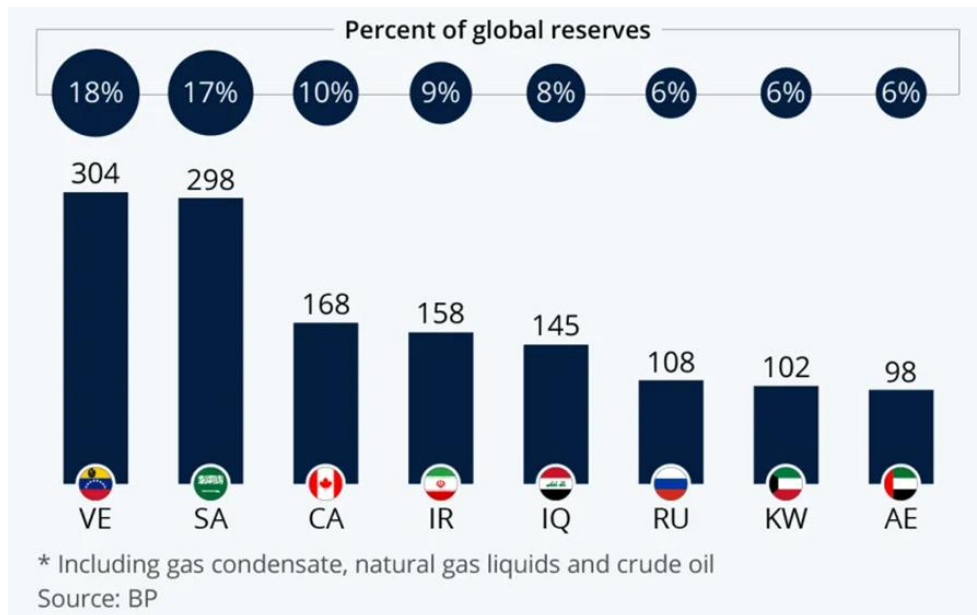


Figure 1. Proven Oil Reserves Ranking by Country (Billion Barrels)

Alternative Estimate of Venezuela's 2P reserves

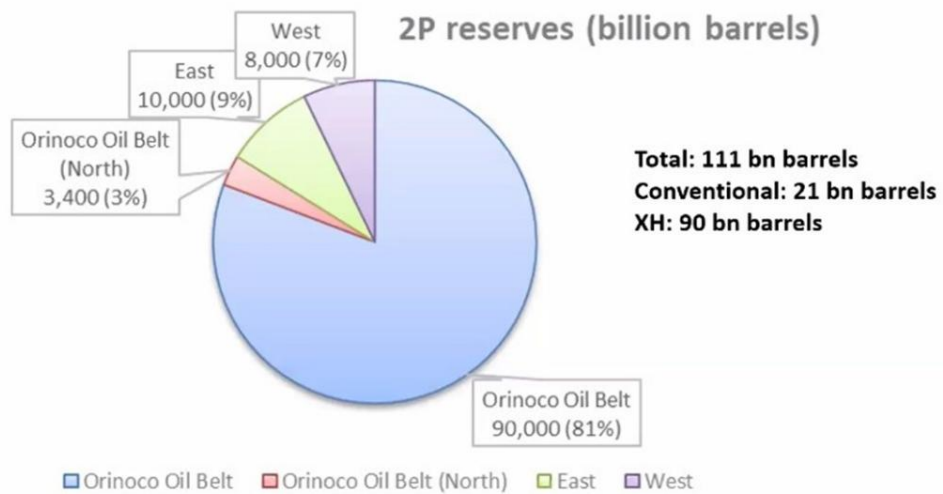


Figure 2. Alternative Estimate of Venezuela's 2P reserves.

Source: Baker Institute for Public Policy, Rice University

1. Current State of the Venezuelan Hydrocarbons Sector

1.1 Nature of the Production Challenge

Venezuelan oil production declined from roughly 3.2 million bpd in 2008 to about 0.85-1.0 million bpd today, not because of resource depletion, but primarily because of poor operational execution, sustained underinvestment, widespread well shutdowns, and deterioration of critical infrastructure. The result is a large stock of idle capacity and a sizeable reopening opportunity for technically capable operators.

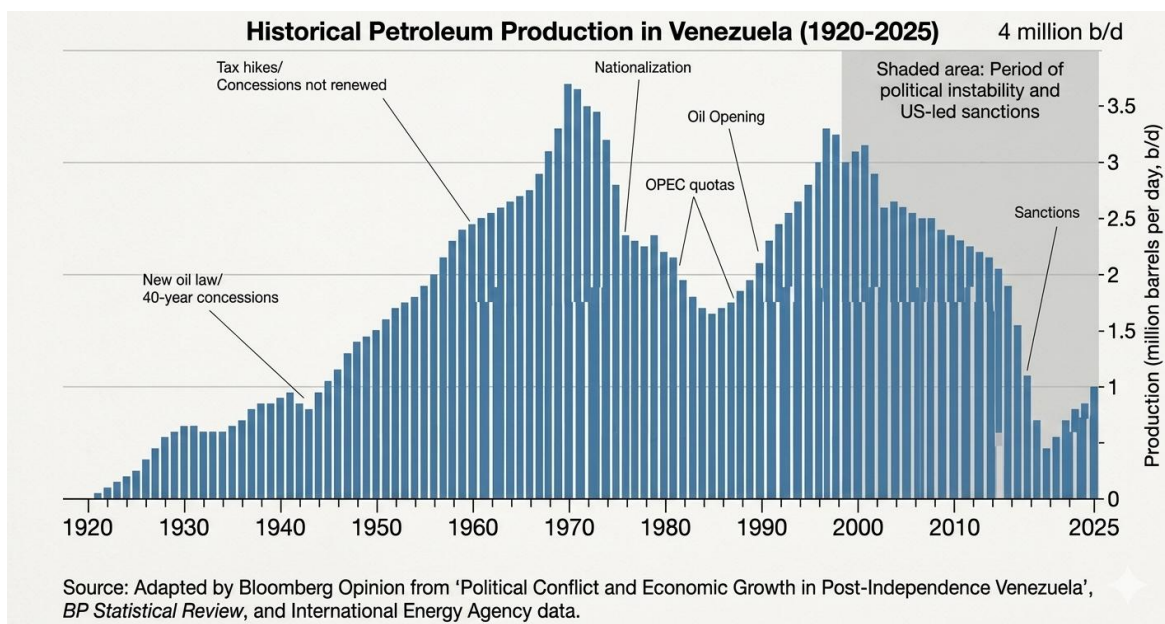


Figure 3. Historical Oil Production in Venezuela, 1920–2023

Historically, the challenge was coordinating assets, services, and logistics in a complex operating environment. Under the new legal framework, private operators with strong technical and commercial capability can potentially turn that complexity into a competitive advantage. A meaningful portion of lost production can be recovered through focused investment in rehabilitation, restart, and selective development.

Venezuela faces OFAC sanctions, but recent general licenses (30b, 46, 46a, 47, and 48) allow recovery of infrastructure and production and facilitate the commercialization of output. These licenses support operational changes, services, procurement, and technology integration using U.S. equipment, which is prevalent in the Venezuelan Hydrocarbons Industry.

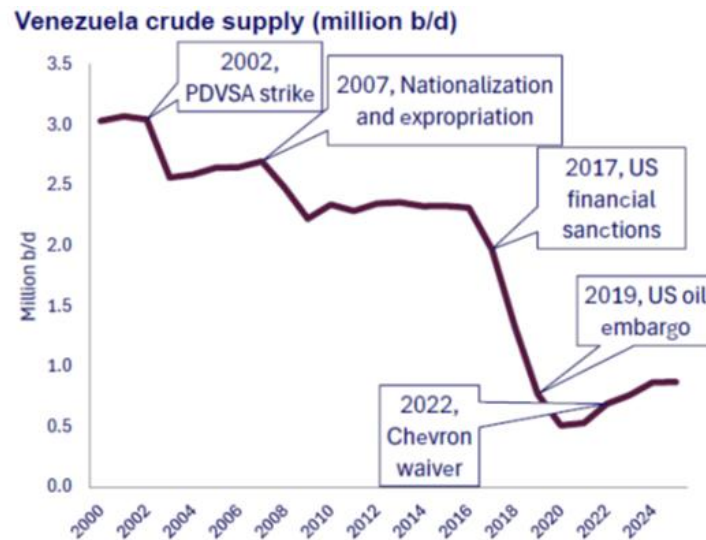


Figure 4. Historical Oil Production in Venezuela, 2000–2025

1.2 Western Venezuela – Maracaibo Basin

Situated between the Venezuelan states of Zulia, Falcón, and Trujillo, near the Colombian border, the western basin has been developed for over a century and boasts the most extensive infrastructure. It currently maintains reserves of approximately 21.482 MMBO primarily consisting of light to medium crude oil. Key features include:

- Predominantly lake-based infrastructure in and around Lake Maracaibo.
- Consolidated access routes and a large installed facilities base.
- Mature fields with thousands of shut-in or low-yield wells.
- Strong potential for rapid production recovery through workovers, reactivation, and basic maintenance.
- Incremental production gains that can often be realized within 12–36 months.

This basin is notable for its established infrastructure and numerous wells that have strong potential for reactivation. The main opportunity involves implementing well repair and routine maintenance strategies, which could lead to medium-term production growth. Achieving operational success relies on efficiently restoring existing assets to quickly resume crude oil flow, particularly in Lake Maracaibo's lake environment.

Sustainable reactivation is contingent upon the availability of critical enabling services. First, the provision of natural gas for Artificial Lift systems (Gas Lift) remains essential as a secondary recovery method, particularly in mature fields. In light of current shortages, prioritizing the restoration of natural gas supply—specifically through the rehabilitation of existing compression plants—is necessary. Second, it is imperative to recommission self-generation electrical systems by undertaking necessary maintenance, thereby ensuring operational stability given existing limitations within the national electrical grid.

Western Venezuela also requires robust lacustrine logistics, including vessels, drilling barges, and subsurface maintenance services. These activities favor operators and service partners with local experience and a practical understanding of Lake Maracaibo reservoir history and operating conditions.

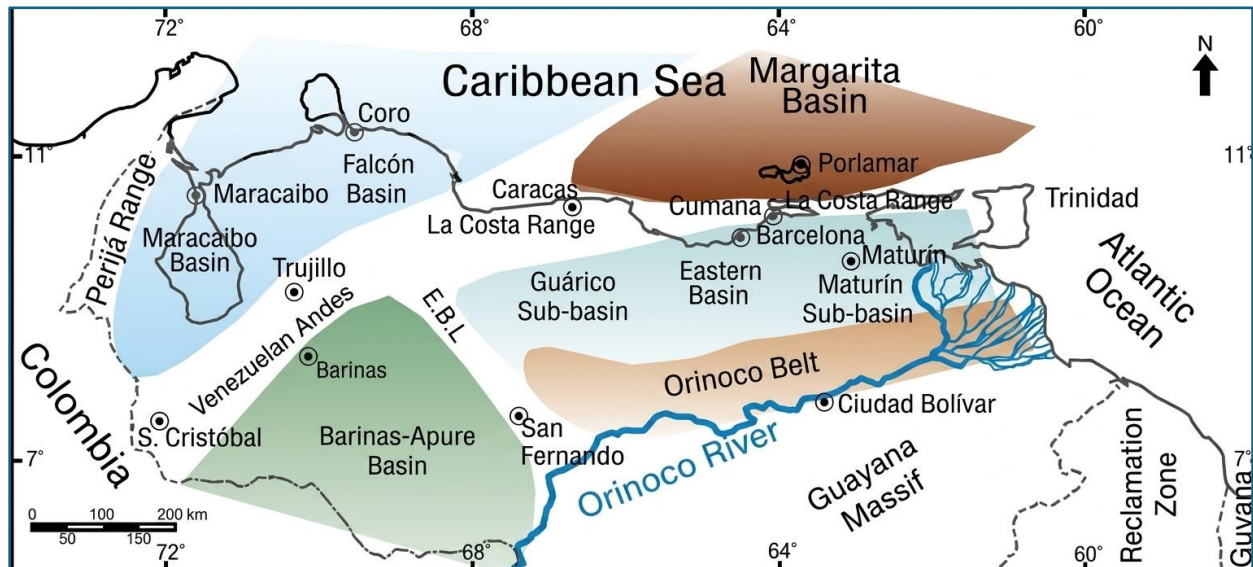


Figure 5. Oil-Producing Basins of Venezuela

Priority work areas in Western Venezuela include:

- Restoration of well services.
- Repair of oil and gas production and transportation lines, many of which present high leakage risk.
- Commissioning and rehabilitation of gas-lift installations.
- Reactivation of self-generation electrical systems.
- Recovery of core logistical services.

1.3 Eastern Venezuela Basin – North Monagas and Anzoátegui

The eastern basin contains major associated-gas resources—about 142 Tcf—and approximately 5.7 Bn bbl of light-to-medium crude reserves. The basin’s development model relies heavily on high-pressure gas injection and technically consistent reservoir management. Key features include:

- Production of light and medium crudes with stronger commercial quality.
- Better onshore logistics than several other Venezuelan provinces.
- Critical need for development drilling and restoration of gas-injection capacity.

This region is strategically attractive because better crude quality and more manageable logistics can compress time-to-market and improve cash realization. However, the operating model is more specialized: restoring high-pressure gas injection systems, maintaining pressure support, and ensuring chemical management are central to basin profitability.

A differentiating factor in the profitability of this basin is the management of subsurface and surface chemical inputs. The use of specialized chemical treatments (such as demulsifiers, corrosion inhibitors, asphaltene precipitants, and flow improvers) is critical to optimize crude segregation.

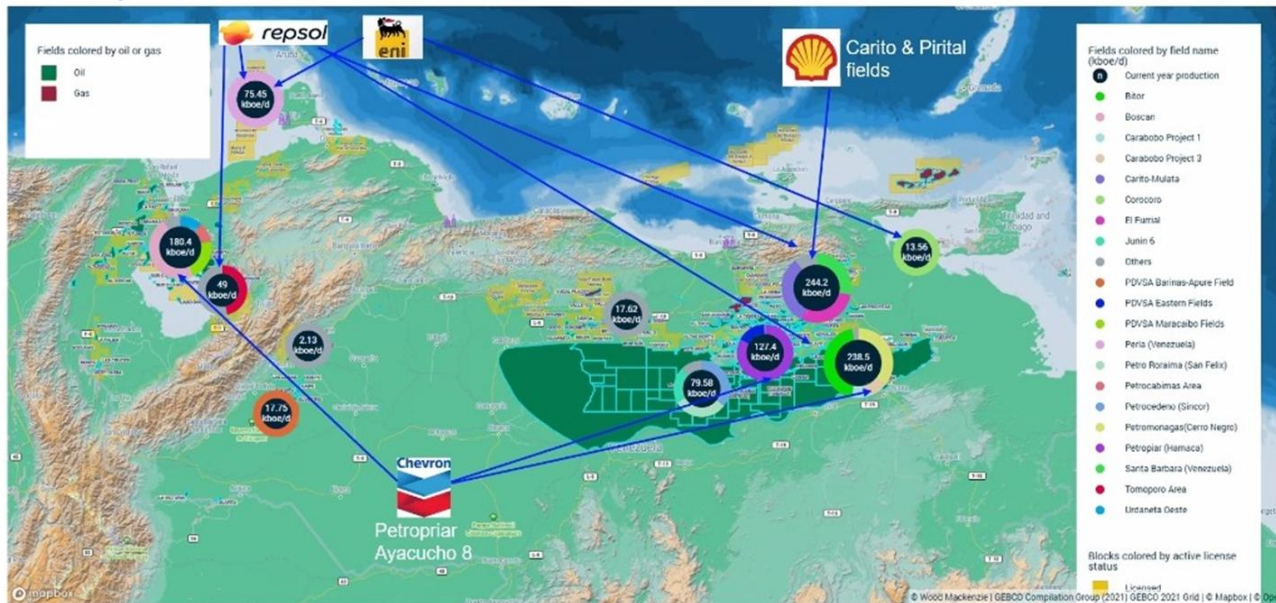


Figure 6. Current Oil Production across Venezuela

Success in this basin relies on development drilling and high-pressure gas injection, which can be managed through private investment in service infrastructure. Reactivating critical plants like the PIGAP (High-Pressure Gas Injection Plant) system under tariff-based contracts allows operational risks to be delegated to specialized managers with appropriate technical and financial capabilities.

Priority work areas in Eastern Venezuela include:

- Restoration of services to producing wells.
- Commissioning and operation of high-pressure gas-injection facilities required for project sustainability.

1.4 Orinoco Oil Belt (Faja Petrolífera del Orinoco — FPO)

The Orinoco Oil Belt is one of the largest oil accumulations in the world. It is characterized by heavy and extra-heavy crude—typically 8° to 13° API—and an estimated resource base of about

273.1 Bn bbl (2P estimated at 90 Bn bbl). The scale is extraordinary, but so are the logistics, handling, and capital requirements.

- Enormous long-term resource potential.
- Extra-heavy crude (<10 API) requiring diluent and disciplined handling.
- High capital intensity and complex logistics.
- Vast undeveloped and underdeveloped acreage.
- Requirements to increase handling and transportation volumes to unlock value.

The business opportunity must focus on a modular development strategy, prioritizing immediate profitability over long-term megaprojects, at least in the initial stage.



Figure 7. Venezuela Orinoco Heavy Oil Belt

The near-term focus should remain on primary recovery, which is technologically straightforward and can sustain production for a long period at relatively low lifting cost. The main bottleneck is commercialization: extra-heavy crude typically requires blending with light crude or naphtha at roughly one barrel of diluent for every three barrels of extra-heavy crude (1:3 bbls).

It's important to keep in mind that investments and costs can differ widely based on the specifics of each field. Greenfield areas typically pose investment challenges and usually require a recovery period of at least five years. In contrast, fields that have already been developed might offer valuable opportunities for short-term production. Under a typical dilution scheme, the resulting stream is about 16° API—an attractive feedstock for several refineries on the U.S. East Coast. Access to North American diluent supply can therefore materially improve project bankability and reduce early reliance on major upgrading investments.

The Orinoco Belt also benefits from a large installed asset base, including upgraders, pumping stations, pipelines, and diluent lines. New opportunities, however, still require targeted rehabilitation and modular expansion.

Priority work areas in the Orinoco Belt include:

- Upgraders as a central pillar of development
- Rehabilitation of existing wells.
- Drilling of new development wells.
- Optimization of existing assets: Rehabilitating transportation infrastructure and separation facilities.
- New support infrastructure: New developments require the construction of modern surface facilities, blending plants, and automated transfer stations. This expansion is necessary to eliminate bottlenecks and connect new production areas with main export nodes.
 - Directional well clusters (*macollas*) to consolidate production and reduce facilities intensity.

Access to international markets remains critical for commercialization of Orinoco production. One option is to source diluent from North American shale to blend with extra-heavy crude, enabling early exports of blended barrels and reducing upfront capital requirements while production ramps up. An alternative and structurally more robust pathway is to prioritize upgrading capacity—for example in José—generating naphtha that can be recycled as diluent back to the Faja.

1.5 The Llanos (Apure and Barinas Basins)

The Llanos region poses engineering and water-management challenges, with fluid handling efficiency as a primary concern. Operators must process substantial water volumes to obtain light and medium crude, so net-barrel profitability is critical. This basin suits companies skilled in large-scale artificial lift and advanced water-treatment technologies. The Barinas–Apure basin is mainly gas prone with a much more limited resource potential than other Venezuelan basins. Key features include:

- Deep drilling targets that increase rig time and cost per foot drilled.
- High water-cuts that require robust separation systems and high-capacity pumps.
- Gas-prone areas in the parts of the basin having more limited resource potential.
- Need to rehabilitate and expand pipeline systems for safe and efficient transport.
- Potential export pull into nearby Colombian markets.

This basin fits companies experienced in large-scale artificial lift, high water-cut operations, and advanced water-treatment systems. The value proposition is not broad-based; it is niche and execution-sensitive with a smaller reserves portfolio compared to other basins.

1.6 Offshore Basins

Venezuela's offshore areas hold large non-associated gas reserves, exceeding 50 TCF, plus some unproven light oil potential. These resources are mainly in Golfo de Venezuela, Plataforma Deltana, Mariscal Sucre, and Golfo de Paria basins—all with commercial reservoirs but lacking adequate infrastructure and contractual terms for profitable development. Recent development projects include Perla (18 TCFG, Repsol–ENI) and Dragon (3 TCFG, Shell), the latter tied to Mejillones and Patao fields. Other basins like Tuy Cariaco, Blanquilla, and Falcon–Bonaire also show commercial promise. Most of the identified fields and discoveries lie in shallow to intermediate water depths (less than 500 m). Main features include:



Figure 8. Venezuela Offshore Basins

- High-quality non-associated gas resources.
- Large undeveloped reserves in current developments and discoveries.
- Strategic proximity to Trinidad and Tobago and to Colombian gas markets.
- Potential for LNG exports, petrochemicals, and domestic power generation.
- Starved domestic market for internal consumption and onshore fields development.
- Long-cycle, capital-intensive projects best suited to majors and large NOCs.

The offshore region represents the least developed hydrocarbons frontier in Venezuela. This is attributable not to limited potential, but rather to substantial investment requirements and the necessity for specialized deepwater and shallow-water infrastructure.

Key opportunities include:

- **Trinidad exports:** Venezuela can short-term monetize its gas by exporting it to nearby Trinidad, using underused LNG facilities like Atlantic LNG, which has four trains and a total capacity of 14 million tonnes per year. This allows rapid monetization, lowers capital exposure, and exhibits strategic alignment with access to global markets.
- **Domestic Natural Gas Supply:** Venezuela faces a persistent electricity shortage in major urban areas, making gas power plants appealing if political stability improves and the electricity market becomes less regulated. Industrial use, refining, and petrochemicals will also shape the future internal gas market. Considering offshore gas could supply the domestic market, its reduced dependence on associated gas

from oil fields would leave more of that gas free to improve oil field performance with gas lift.

- **Petrochemical Expansion:** Large offshore gas reserves could also enable growth in methanol plants, ammonia and urea complexes, and plastics and derivatives.
- **Long-Term LNG Development:** Besides the Trinidad exports business proposition (currently under Shell Dragon gas field), Venezuela's offshore basins, including Golfo de Venezuela and Carupano gas fields, offer proven reserves for a potential LNG export strategy. These fields could support future western and eastern LNG hubs, enabling regional integration with global markets currently dominated by US hubs.

Operational and Development Challenges

Offshore development requires costly specialized offshore drilling rigs, advanced subsea infrastructure and completions, long-distance pipelines (50 to 150 km), high-pressure gas processing plants, complex logistics and marine operations, plus lengthy development timelines of 5 to 10 years. Despite these challenges, offshore Venezuela remains one of the largest undeveloped gas provinces in the Western Hemisphere, competing only with Vaca Muerta unconventional gas play and offshore Colombia undeveloped gas discoveries, making it a very valuable long-term strategic asset for the majors.

2. Legal and Fiscal Framework of the 2026 Hydrocarbons Reform

The January 2026 partial reform of the Organic Hydrocarbons Law (LOH) is the most significant change to Venezuela's upstream framework in more than two decades. Its stated objective is to restore project economics, attract private capital, and stabilize production through a more flexible contractual and fiscal architecture. The emerging contractual architecture is expected to converge toward internationally recognizable models. In particular, Venezuela's Contratos de Participación Productiva (CPP) can be readily mapped to international Production Sharing Agreements (PSAs), where investor returns are directly linked to production and project economics. Under these contractual structures, private operators assume operational responsibility, recover investments, and participate in production-based returns, while the State captures value through a negotiated share of profits and fiscal terms. This alignment with globally tested frameworks enhances comparability, reduces structural uncertainty, and facilitates benchmarking against other upstream jurisdictions.

2.1 Core Features of the Reform

The revised framework is designed around five concepts that matter directly to investors:

- Economic equilibrium.
- Operational flexibility.
- Private participation.
- Transparent commercialization mechanisms.
- More competitive fiscal terms.

2.2 Fiscal Regime Simplification

The previous fiscal structure often pushed the government take into the range above 90%, making many projects financially unviable. The 2026 reform aims to move projects toward a more competitive range—potentially around 50% to 70%, depending on the negotiated development plan, capital intensity, and technology requirements.

To support competitiveness, the revised model contemplates:

- Royalty adjustments.
- Income-tax simplification.
- Elimination or rationalization of overlapping contributions.
- Negotiable fiscal terms tied to project economics.

The practical significance is that fiscal design becomes part of the investment case rather than a fixed constraint. Early definition of scope, production profile, facilities, and commercialization assumptions is therefore critical during contract negotiations.

2.3 Contract Structure and Economic Equilibrium

A central innovation of the reform is the use of economic-equilibrium concepts intended to protect project profitability against adverse changes during the life of the contract. In principle, these mechanisms can provide a basis for rebalancing if fiscal, regulatory, market, or operating conditions materially impair the economics originally agreed by the parties.

For investors, the key issue is not only the existence of these clauses, but also how they are implemented: trigger definitions, measurement methodologies, approval mechanics, and dispute-resolution pathways should be refined in subsequent contractual documentation.

The reform also contemplates long-dated contracts—up to 20 years, extendable where warranted by reservoir characteristics, investment intensity, and production profile. That duration is especially important for Orinoco, offshore gas, and major brownfield rehabilitation programs.

2.4 Direct Commercialization of Production

To strengthen investor confidence, the reform allows direct commercialization of hydrocarbons by the operator into international markets. Strategically, this matters because it can improve transparency, accelerate cash collection, and reduce counterparty and intermediation risk.

- The operator sells its allocated production directly into international markets.
- No government intermediary is required for the sale process.
- Cash flow is managed directly by the operator.
- Payment is received directly from buyers.
- Financial-intermediation risks are reduced.

If implemented consistently, these provisions can materially improve monetization certainty and speed-up capital recovery.

2.5 Private Participation Structures

The reform enables direct private participation in exploration, production, infrastructure, and commercialization activities through two principal mechanisms:

a) Joint Ventures (Empresas Mixtas)

- Majority ownership remains with the Venezuelan state.

- The private partner may operate the asset.
- Development plans are jointly approved.
- The operator leads execution and commercialization.

b) Operating Contracts (100% Private)

- The private operator assumes full operating responsibility.
- The contract is signed with PDVSA and/or the mixed enterprise.
- The operator manages production, infrastructure, and commercialization.
- The state receives royalties and taxes.

This dual model allows flexibility depending on the company size and appetite, the asset, investment scale, and operational complexity. Most likely large ventures such as heavy oil or offshore gas projects will remain in the Empresa Mixta format, while brownfield and rehabilitation projects will be Operating Contracts. The reform allows contracts of up to 20 years, extendable based on reservoir traits, investment, and production. These long-term contracts are crucial for capital-heavy projects like those in the Orinoco Belt, offshore gas, and major onshore rehabilitation programs including the Maracaibo basin.

Each project must include a negotiated Development Plan (PoD), which becomes a central commercial and operational document. The PoD should define production targets, capital and operating cost profiles, infrastructure requirements, drilling programs, environmental obligations, and the commercialization strategy that underpins project economics.

3. Strategic Implications for Investors

For prospective entrants, the current Venezuelan opening is less a pure geology story than an execution and structuring story. Different investor types are likely to find opportunity in different parts of the value chain.

3.1 Where Different Investors May Find the Best Fit

| Investor profile | Most attractive entry route | Why it fits |
|---|---|--|
| Mid-cap independents and regional operators | Brownfield rehabilitation in Maracaibo and selected eastern assets | Lower technical risk, faster cash flow, and clearer line-of-sight to production restoration. |
| Large IOCs and NOCs | Orinoco mixed enterprises and offshore gas | Scale, reserve replacement, long duration, and ability to absorb complex capital programs. |
| Service-backed platforms / infrastructure investors | Compression, gas handling, power, logistics, chemicals, and facility rehabilitation | Performance-based contracts can unlock value without taking full field risk. |
| Financial sponsors with operating partners | Structured brownfield portfolios and staged redevelopment | Opportunity to aggregate undervalued production upside under tighter capital discipline. |

3.2 What Sophisticated Clients Should Pressure-Test Early

- The enforceability and detailed mechanics of economic-equilibrium protections.
- Domestic market obligations and whether they affect pricing or lift rights.
- Sanctions pathways, counterparties, and compliance architecture.
- Whether the development plan assumptions realistically reflect logistics, gas handling, power, and chemical requirements.
- Whether the selected contract structure matches the asset’s technical and commercial reality.

4. Investment and Operational Strategy

Venezuela's current industry status enables a dual-path investment: short-term production recovery via field rehabilitation of legacy assets, combined with scalable long-term development targeting PUD Proven (P1) and Probable (P2) reserves. This approach delivers immediate cash flow and supports sustainable growth for future operations.

4.1 Rehabilitation of Legacy Assets (Brownfield)

Many mature or legacy fields with existing infrastructure are non-operational or shut-in due to prolonged underinvestment, inadequate maintenance, shutdowns, pipeline and facility deterioration, reduced gas-injection capacity, electrical failures, and infrastructure damage.

Despite the challenges, these assets provide a quick route to production growth and cash flow, since reservoir performance is understood and existing infrastructure allows low-cost reactivation of wells. Workovers and basic maintenance can yield fast results and strong cash flow within 6–24 months. This path is ideal for operators seeking rapid monetization and lower technical risk.

Typical brownfield work scopes include:

- Well repairs and workovers.
- Reactivation of shut-in wells.
- Optimization/restoration of artificial lift systems.
- Repair of flowlines and trunklines.
- Reactivation of electrical self-generation.
- Optimization of separation and treatment systems.
- Recovery of field logistics and services.

4.2 Development of New Fields (Greenfields)

Greenfield developments—especially in the Orinoco Belt—represent Venezuela’s principal long-term growth avenue. These projects require robust subsurface characterization, staged development planning, realistic service assumptions, and disciplined facilities design to avoid overcapitalized megaproject structures.

Key Activities in Greenfield projects (Orinoco heavy oil type)

- Sound development plans with updated CAPEX and OPEX assumptions.

- Drilling programs grounded in regional know-how.
- Surface facilities procured and built on market terms.
- Renewal or replacement of pipelines and gathering systems where needed.
- Diluent supply systems, blending plants, storage, and export infrastructure.
- Phased modular growth with directional well clusters and scalable facilities.

Under the new framework, the winning operators are likely to be those that combine execution discipline, cost control, logistics management, reservoir surveillance, and consistently high uptime rather than those relying on a purely macro or speculative thesis.

5. Strategic Risk Assessment

The opportunity has become more bankable, but it is still not a low-friction market. Investors should weigh first-mover advantage against a focused set of implementation risks and practical guardrails.

| Risk category | Key uncertainty | Potential mitigation / guardrail |
|--------------------------|---|---|
| Legal and Regulatory | Durability of rule of law beyond the written contract. | International arbitration, strong contract drafting, and careful choice of counterparties and dispute venues. |
| Institutional | Shift from a rigid regime to a more discretionary administrative model. | Detailed economic-equilibrium language, measurable triggers, and governance procedures embedded in contracts. |
| Operational | Domestic market obligations and field-level execution bottlenecks. | Clear commercialization provisions, realistic development plans, and secure logistics / power / gas-handling assumptions. |
| Infrastructure | Degraded assets, unreliable power, leakage, and service-chain disruption. | Phased rehabilitation, self-generation, performance-based service contracts, and early facilities triage. |
| Geopolitical / Sanctions | OFAC sanctions, licensing, and political volatility. | Robust compliance architecture, scenario planning, and transaction structures consistent with applicable licenses. |

6. Project Economics: Government Take & Example cases

The 2026 reform materially changes the economic profile of Venezuelan upstream projects by reducing government take and enabling more flexible fiscal structuring. As a result, project economics are now primarily driven by execution discipline—CAPEX control, OPEX efficiency, uptime, and commercialization strategy rather than by resource access alone. This section illustrates the impact of the new framework through indicative government-take comparisons and representative project cases across key Venezuelan asset types.

6.1 IRR and Government Take

The reform’s most immediate impact is the reduction and increased flexibility of government take, which improves investor returns across all asset classes. Under the previous regime, government take frequently exceeded 80%–90%, effectively limiting most projects to marginal or non-viable outcomes. Under the new framework, government take is reduced to a more competitive range—typically ~50%–60% depending on the development plan and contractual structure—allowing projects to generate materially higher IRRs even at conservative oil price assumptions. The charts below illustrate how post-reform structures improve returns across representative asset types, particularly in brownfield opportunities where capital intensity is lower and production recovery can be achieved rapidly. The dispersion of IRRs reflects differences in capital intensity, crude quality, and logistics, with brownfield projects consistently outperforming large-scale greenfield developments on a risk-adjusted basis.

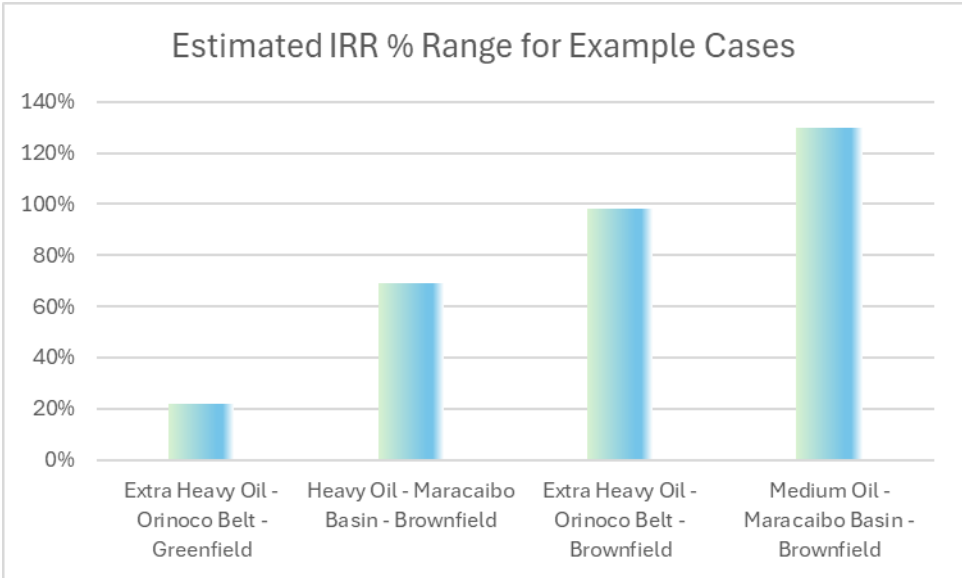


Figure 9. Venezuela IRR project comparison for different example cases. Extra Heavy Oil at Orinoco at 70% Private participation, through expected reduction of fiscal load. All others at 55%

6.2 Example Cases

To illustrate the practical implications of the new fiscal framework, the table below presents representative project economics for selected Venezuelan case types. These cases are not asset-specific, but rather indicative scenarios based on typical operating conditions, cost structures, and development approaches observed in each basin. The results highlight a key strategic insight: value creation in Venezuela is driven less by oil price assumptions and more by disciplined execution, capital efficiency, and the ability to rapidly restore or scale production. Brownfield projects—particularly in western Venezuela—offer strong IRRs and short payback periods, while more capital-intensive developments provide longer-term reserve and production growth.

| Project | Medium oil Brownfield West Maracaibo Lake | Heavy oil Brownfield West |
|--------------------------------------|--|--|
| Private % | 55% | |
| Brent Price | \$60/bbl | |
| Total Capex - 20 year (\$ MM) | \$1,189 | \$297 |
| OPEX (Lifting Cost) \$/Bbl | \$12 | \$5 |
| Max. Production kbpd | 72 | 34 |
| Financing Peak (\$ MM) | \$39 | \$75 |
| NPV10 (\$ MM) | \$1,062 | \$708 |
| IRR | 199% | 69% |
| Payback (Yrs.) | 1 | 3 |
| Breakeven Price | \$40/bbl | \$25/bbl |
| Fiscal regime assumptions | | |
| Royalty | 30% | |
| Integrated Carbon Tax | 15% | |
| Income Tax | 50% | |

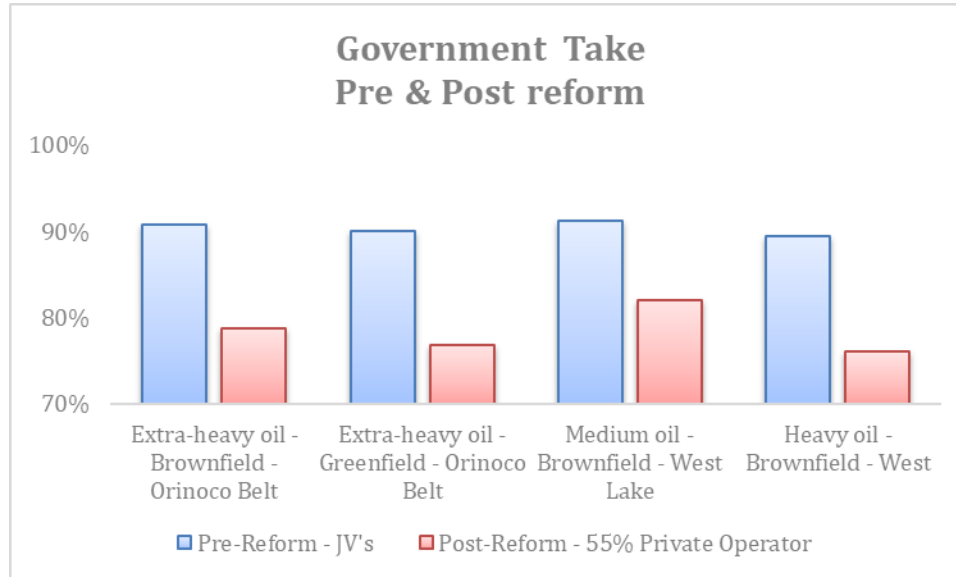


Figure 10. Venezuela GT Project Pre and Post Reform Comparison

7. Outlook and Conclusions

Venezuela’s hydrocarbons sector is moving toward a more investable model built on legal reform, fiscal flexibility, direct commercialization, and a clearer role for private operators. The opportunity is real, but returns will depend on disciplined execution and careful structuring rather than on resource size alone.

The strategic outlook rests on four conclusions:

- A more competitive legal and fiscal framework improves investment scenarios, even though implementation detail remains critical.
- A dual investment model—brownfield for early cash flow and greenfield for longer-term scale—creates a balanced entry path.
- Operational efficiency is now the core value driver: technical excellence, logistics, artificial lift, chemical management, and facilities reliability will separate winners from underperformers.
- Offshore gas should become a strategic pillar of the country’s future energy system, with relevance for domestic supply, petrochemicals, Trinidad-linked monetization, and longer-term LNG optionality.

If contract implementation remains broadly aligned with the reform’s intent, Venezuela could re-emerge as a reliable supplier of heavy and medium crude, a future LNG contributor, and a strategic partner for regional energy security.

8. Why Plata Energy

Plata Energy is uniquely positioned to support investors entering Venezuela’s next phase, combining operational, contractual, and M&A transaction experience, with deep hands-on in-country knowledge.

Our partners have led some of the most significant hydrocarbon discoveries and developments in Venezuela in recent years, including **Perla - Cardón 4** mega gas field, **Sincor** and **Hamaca** heavy oil projects and **PetroQuiriquire** light oil and gas development, among many others.

Our professionals have operated across all five major Venezuelan basins, working with leading international companies such as **Eni, Chevron, Shell, Repsol, TotalEnergies, and Equinor**, consistently delivering measurable production and value creation outcomes under complex operating conditions.

Recently, as advisors, we have successfully supported strategic transactions, including:

- The E&P contract negotiation and signature country entry of an operator into the Orinoco Belt (Faja Petrolífera del Orinoco) (2023-2024)
- The recent E&P contract signature and country entry into assets in the Oficina area, Eastern Venezuela (2024)

Our team integrates all key capabilities required to succeed in Venezuela:

- Exploration, development, and production expertise
- Facilities, logistics, and operational execution
- M&A, commercial structuring, and negotiations
- Regulatory and in-country operational knowledge

Plata Energy is recognized as a leading advisory platform in Venezuela. We combine international senior expertise with strong local execution capabilities, bridging the gap between global capital and in-country realities. We are headquartered in Houston, TX—an increasingly critical factor in today’s regulatory and sanctions environment—while maintaining strong operational and strategic ties to Venezuela. This positioning allows us to help investors move decisively, structure effectively, and execute successfully in one of the most complex and high-potential upstream markets in the world.