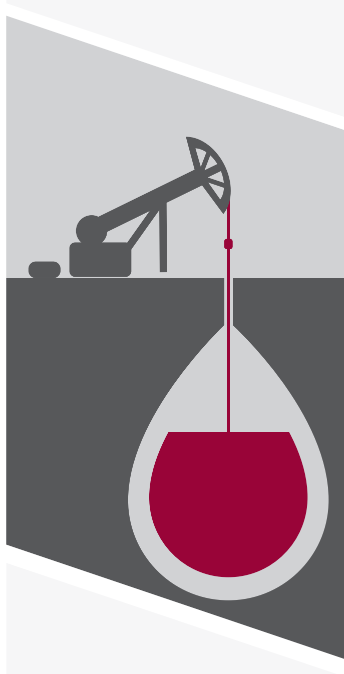
IESA
INTERNATIONAL CENTER
ON ENERGY AND THE ENVIRONMENT

ENERGY IN FIGURES

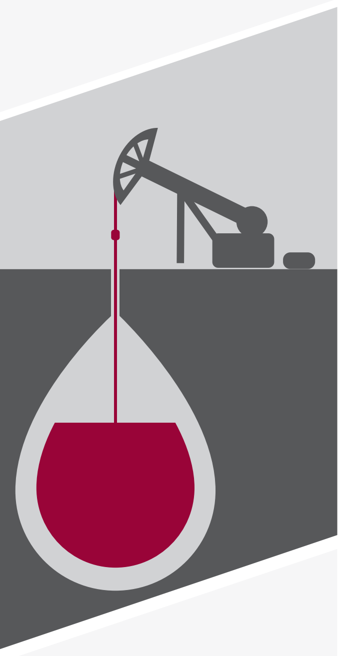
OIL AND GAS SECTOR

2014 / 2015

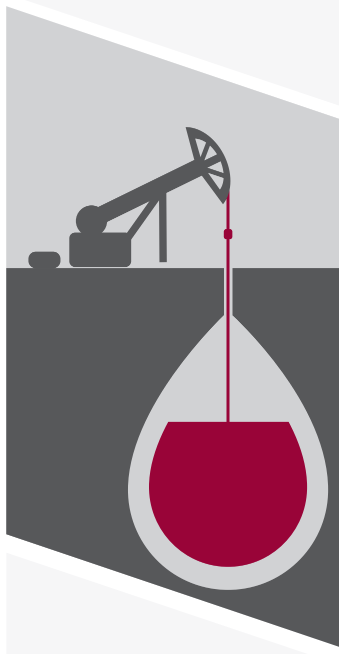
VENEZUELA

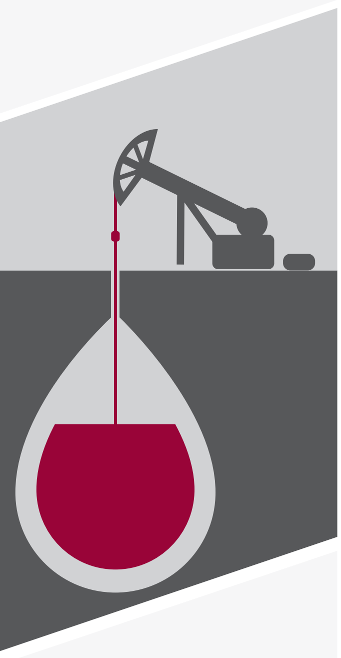


Content



Figures and tables





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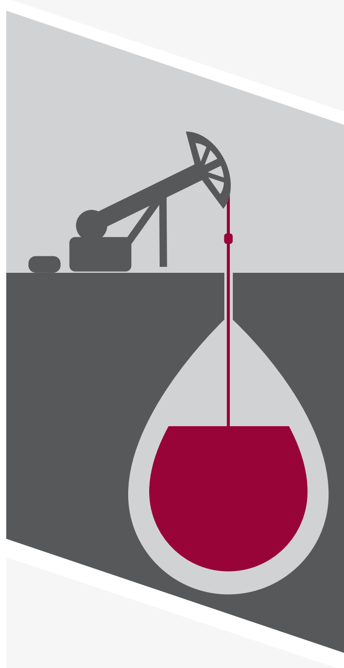


NOTATIONS AND ABBREVIATIONS

bcf: billions of cubic feet
bcm: billions of cubic meters
boe: barrels of oil equivalent
LNG: liquefied natural gas
mbd: million barrels per day
mboe: million barrels of oil equivalent
mcm: million cubic meters
mcfd: millions of cubic feet per day
tbd: thousand barrels per day

ACRONYMS

BCV: Banco Central de Venezuela (Central Bank of Venezuela)
EIA: U.S. Energy Information Administration
IEA: International Energy Agency
IMF: International Monetary Fund
MEFBP: Ministerio de Economía, Finanzas y Banca Pública, Venezuela (Ministry of Economy, Finance and Public Banking)
MENPET: Ministerio del Poder Popular de Petróleo y Minería, Venezuela (Ministry of Petroleum and Mining)
OPEC: Organization of the Petroleum Exporting Countries
PODE: Petróleo y Otros Datos Estadísticos (Petroleum and Other Statistical Data)
USD: United States Dollars
WTI: West Texas Intermediate

EXECUTIVE SUMMARY

The International Center on Energy and the Environment (CIEA) of the Instituto de Estudios Superiores de Administración (IESA) presents a new edition of Energy in Figures. Our 2014-2015 issue reviews the most relevant indicators on the chain value analysis of hydrocarbon business in Venezuela and a part of the rest of energy industry focused on current market transition and trends. **Energy in Figures** compiles the last official data releases from the Venezuelan Oil and Mining Ministry and Petróleos de Venezuela, S.A. (PDVSA, the national oil company), as well as from the most relevant international sources, such as BP, OPEC, IEA and EIA.

The first and second sections of the report examine the most recent figures on oil and gas sector in Venezuela. The third section contains exclusive contributions on key issues for the industry and current trends of the market from leading experts. In the fourth section we compile recent work from **CIEA** staff's research to disseminate the sector current landscape, and the final section shows long-term projections on oil and gas industry consumption and production patterns in light of current and future energy matrix.

Oil Sector

Oil outlook

Table 1 Oil sector in 2014

		RESERVES (BILLIONS OF BARRELS)	PRODUCTION (MBD)	CONSUMPTION (MBD)
WORLD		1700.1	88.7	92.1
AMERICAS		563	26.3	30
VENEZUELA	CONVENTIONAL CRUDES	22.522	1,145	
	HEAVY AND EXTRA HEAVY CRUDES	277.431	1,640	
	TOTAL [1]	299.953	2,685 - 2,785	0,663 – 0,781
SHARE OF CONVENTIONAL CRUDE RESERVES [2]			SHARE OF TOTAL PRODUCTION	SHARE OF TOTAL CONSUMPTION
VENZUELA /WORLD		2%	3,14% - 3,02%	0,72% - 0,85%
VENEZUELA / AMERICAS		19%	10,2% -10,57%	2,17% - 2,56%
SHARE OF TOTAL RESERVES [3]				
VENEZUELA/ AMERICAS	53%			
VENEZUELA/ WORLD	18%			

Source: Statistical Review of World Energy (BP, 2015), Management Report 2014 (PDVSA, 2015).

[1] Higher production and lower consumption figures were published by PDVSA (2015).

[2] Includes condensate, light and medium crudes. Does not include wet gas.

[3] Includes condensate, light, medium, heavy and extra-heavy crudes.

Oil outlook

Table 2 Oil sector in 2015

		RESERVES (BILLIONS OF BARRELS)	PRODUCTION (MBD)	CONSUMPTION (MBD)
WORLD		1696.6	91.7	95.0
AMERICAS		570	27.4	31
VENEZUELA	CONVENTIONAL CRUDES	22.667	1,149	
	HEAVY AND EXTRA HEAVY CRUDES	278.209	1,597	
	TOTAL [1]	300.876	2,626- 2,746	594 – 678
SHARE OF CONVENTIONAL CRUDE RESERVES [2]			SHARE OF TOTAL PRODUCTION	SHARE OF TOTAL CONSUMPTION
WORLD		2%	2,86% - 2,99%	0,63% - 0,71%
VENEZUELA / AMERICAS		18%	9,59% -10%	1,93% - 2,20%
SHARE OF TOTAL RESERVES [3]				
VENEZUELA/ AMERICAS	53%			
VENEZUELA/ WORLD	18%			

Source: Statistical Review of World Energy (BP, 2015), Management Report 2014 (PDVSA, 2015).

[1] Higher production and lower consumption figures were published by PDVSA (2015).

[2] Includes condensate, light and medium crudes. Does not include wet gas.

[3] Includes condensate, light, medium, heavy and extra-heavy crudes.

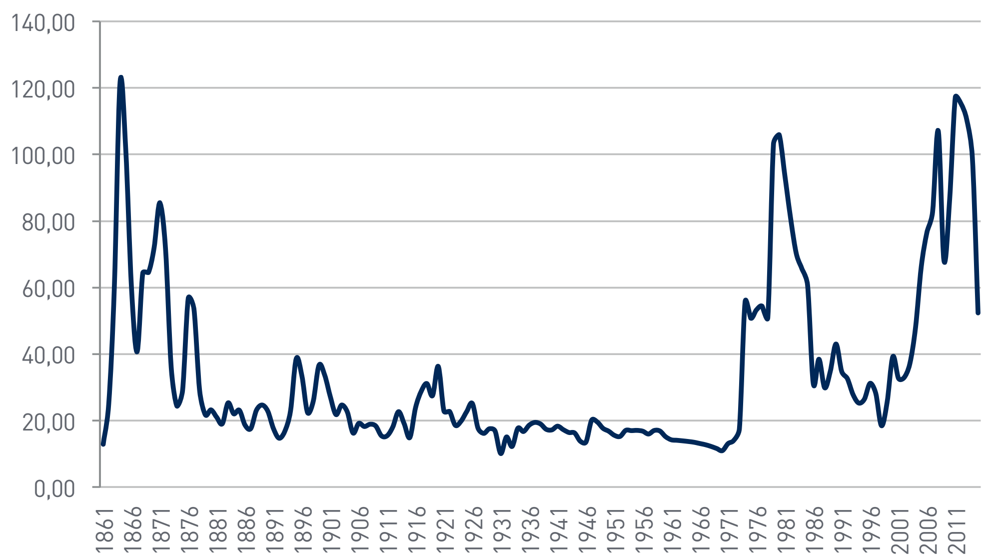
Oil Prices

Recent developments suggest that 2014 was a pivotal year for oil market and prices in recent history. Brent crude averaged 98.65 USD per barrel, showing a 10% decline as compared to 2013 real price. Venezuelan basket price reached an average 88.42 USD per barrel, a 12% year-on-year (yoy) drop. Crude prices remained historically high on average.

Nonetheless, monthly series show a 44% collapse in oil prices as of December 2014, when the Venezuelan basket real price fell to 22.87 USD per barrel, a six-year low not seen since 2007-08 international financial crisis. This breakdown in prices started at the last quarter, having a small impact on annual average prices.

During 2015, oil real price reached 52 USD per barrel, a 47% yoy slump. Venezuelan basket price fluctuated between 30 and 56 USD per barrel, while on 2014 prices ranged from 54 to 98 USD per barrel. Venezuelan basket slump extended until February 2016, when the price was 24.15 USD per barrel. In December 2015, yoy drop reached 69%.

Figure 1 Venezuelan oil basket, 2015 prices (January 1993 – June 2016)



Source: Statistical Review of World Energy (BP, 2015) and FRED (St. Louis FED, 2016) [1]

[1] 1861-1994: Average U.S. price. 1945-1983: Arabian Light crude price posted at Ras Tanura. 1987-2015: Brent dated price..

Figure 2 Venezuelan oil basket, 2015 prices (January 1993 – June 2016)

Source: Venezuelan Oil basket (MENPET, various years) and FRED (St. Louis FED, 2016).

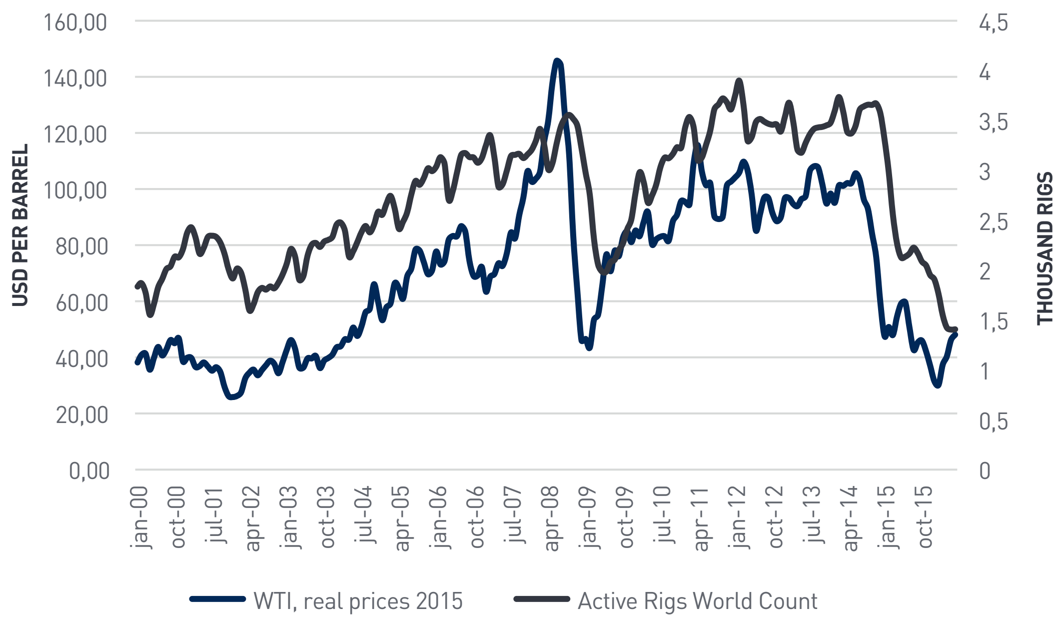
Three basic fundamentals have been suggested to explain this price downfall: U.S. unconventional production growth, slow global economic growth and Saudi Arabia negative position on production cuts. U.S shale-oil projects are responsible for most of production growth and imports reduction in that country. Meanwhile, oil demand has lost dynamism due to lower-than-expected economic performance, mostly in Asian and advanced economies. Finally, Saudi Arabia refuses to change its market approach as the kingdom tries to reassess its growth strategy.

Drilling activity has shown a strong correlation with oil price fluctuations, with some studies estimating unit price-elasticity in the long term[1]. This relation varies between regions due to the different type of crude reserves development.

[1] Ver Ringlud, G.B.; Rosendahl, K.E.; and Skjerpen, T. (2008) Does oil rig activity react to oil price changes? An empirical investigation. Energy Economics, v. 30, n. 2, pp. 371-396.

U.S. accounted for 52% of total world drilling activity during 2014. This was mainly related to the particular production technology and process of most shale producers. The difference in production techniques, which combines horizontal drilling and hydraulic fracturing, has reduced delays between investments and production and it made the U.S. shale and tight oil supply more elastic to prices. Recently, the shift in non-conventional sources production motivated a battle for market share between conventional producers and American shale producers, a main driver for recent oil price slump.

Figure 3 Active rigs and oil price (January 2000 – June 2016)



Source: International Rotary Rig Count (Baker Hughes, 2016), FRED (St. Louis FED, 2016).

Probably as a consequence of the oil price slump, drilling activity has shown a downward trend since November 2014. Active rigs reached a minimum since 2000 in May 2016.
The counts dropped 34% in June, as the price shows a small recovery. Most of rig activity decrease in 2016 originates from the United States and Canada, maybe due to the loss of competitiveness of unconventional producers from Texas and Alberta.

BOX /1

THE FALL IN PRICES AND THE NEW STATE OF AFFAIRS IN THE INTERNATIONAL OIL MARKETS

- BY ARMANDO ROMERO -

The recent crude oil price slump, which started in the last quarter of 2014 and became more intensive since the end of 2015 and 2016, might be the result of deep changes in international oil markets dynamics. Venezuelan crude oil basket closed 2015 in 29.15 USD per bbl, down from 97.09 USD per bbl in 2013 and 49.52 USD per bbl in 2014. This implies a loss of 69% in its price since 2014.

By mid-January, international price benchmarks as West Texas Intermediate reached a 12 year low, prompting some actions from big producers in February, for which a recovery is expected in upcoming months. Nonetheless, projections sustained that low prices –as compared to recent all-time highs- will remain in the immediate future. Many analysts suggest the market found a new equilibrium in lower levels than recent 100 prices per barrel. In contrast to 2009 drop, the recent plunge in prices might not be related to international financial markets instability but to structural changes in oil markets. The outbreak of new supply and the change in strategy of traditional suppliers have been combined with changes in demand profile which has been reducing its growth rate in recent years. Traditionally, oil producers and consumers response to changes in the market have been slow, for which prices can undergo a change significantly in the short-term. This box resumes some of the events that are generating profound changes in global crude oil markets.

The Shale Oil revolution

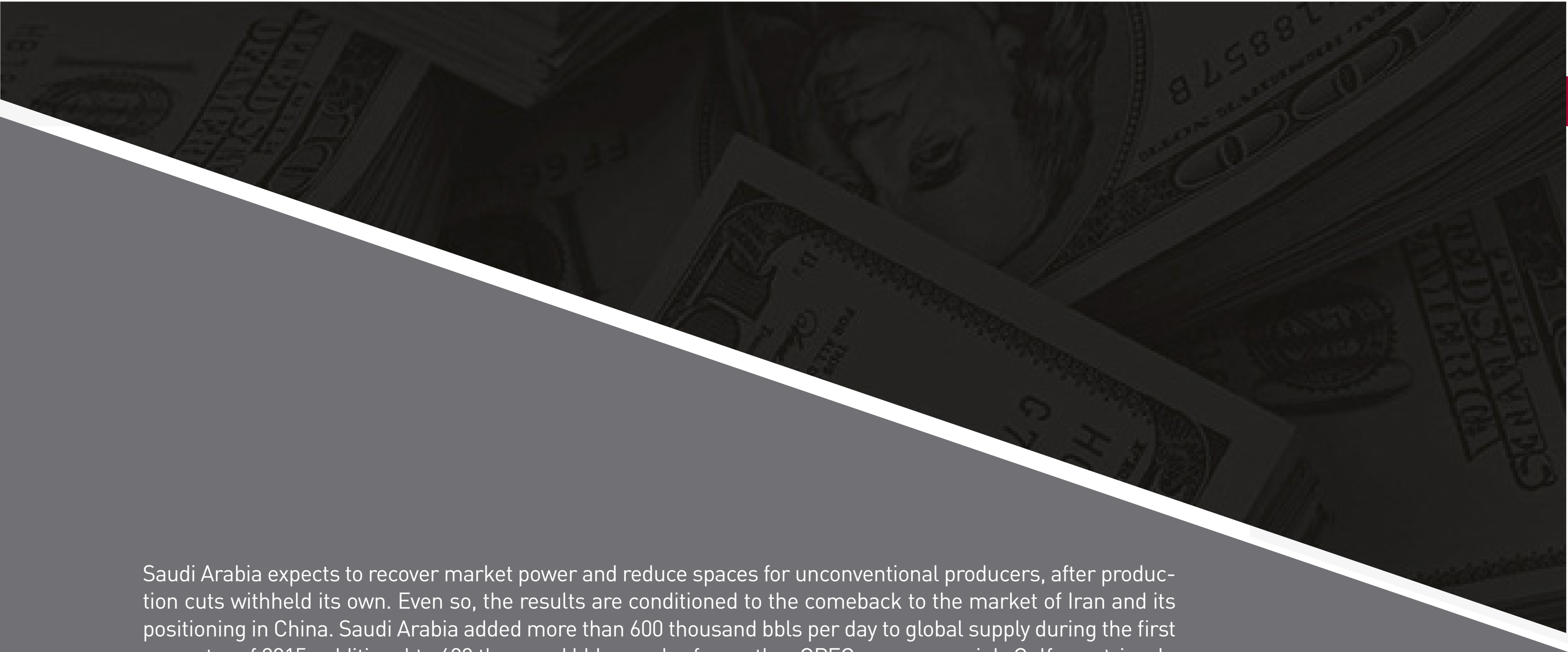
Production grew as never seen before since 2006 due to combined use of horizontal drilling and hydraulic fracturing in shale rock formations in the United States.

Shale revolution is the reason behind the addition of more than five million bbls per day to world crude oil supply until 2014. Even when shale costs are higher than conventional supply, productivity augmented significantly in terms of drilling time, wells achieved per drill and barrels produced per day. Productivity gains allow United States producers to cover operational expenses and continue pumping, turning this country into the first world producer, surpassing Russia in 2011 and Saudi Arabia in 2012. Crude oil production grew by more than 400 thousand bbls per day by the first quarter of 2015, as low prices caused a reverse in 2016. Besides, the United States lifted a ban on oil exports –dated back to 1973- by the end of 2015 and the first crude oil was exported in January 2016. Recently PDVSA bought 550 thousand bbls of WTI, the first recent crude shipment sent to Latin America since the ban lifting.

As long as the oil price allows to cover operating costs, a substantial amount of additional production will not disappear despite price slump. Although drilling activity fell by 62% and 80% in horizontal drilling in 2015, and production is expected to decline 600 thousand bbl per day in 2016, productivity gains seems to indicate that shale oil will remain in the market, even with low prices. Some analysts estimate that shale supply exit would stop at 45 USD per bbl, a level that could be reached by the end of 2016.

Saudi strategy and the OPEC

Saudi Arabia, which accounts nearly 40% of OPEC production, is the most influential member of the organization and all of the relevant decisions are conditioned to its support. In response to global oil supply changes caused by the entrance to the market of shale oil, the country has decided to modify substantially its strategy in order to maximize its long term profits. A strategy which is largely supported by its Gulf allies. Until 2014, OPEC agreed to compensate oil demand and supply shocks by reducing or augmenting production –mainly Saudi Arabian production- and maintain prices near 100 USD per bbl. Nonetheless, supported by its cost advantages, the new Saudi strategy consists in recover old and gain new market shares by increasing oil pumping in the short term, even when prices have fell drastically and against other OPEC members requests for production cuts.



Saudi Arabia expects to recover market power and reduce spaces for unconventional producers, after production cuts withheld its own. Even so, the results are conditioned to the comeback to the market of Iran and its positioning in China. Saudi Arabia added more than 600 thousand bbls per day to global supply during the first semester of 2015, additional to 600 thousand bbls per day from other OPEC sources, mainly Gulf countries. In spite of the recent production declining, the OPEC have decided to hold the current position, even more after considering its effects in unconventional sources, which has been reduced drastically. Meanwhile, Saudis are applying a macroeconomic adjustment in order to resist low prices with spending cuts, new taxes and a possible IPO of ARAMCO

China and the global slowdown

Global growth rates fell by half in 2010-2014. Without exception, every region in the world underperformed since then, including a recession in the EU and a slow recovery from the Great Recession which started back in 2008. Fuels consumption have been particularly sensitive to this stagnation phenomenon, with a generalized decline of a third in crude oil demand growth which goes up to a half in the case of Asian countries. The case of China is particularly relevant given its responsibility in explaining demand growth expansion in the previous decade (30% according to the IEA), which relates this economy deceleration, intensified by recent exchange rate devaluation and financial markets unrest, to the crude oil demand growth, without any other consumers in a global slowdown context.

Recently, industrial activity indicators and fuels demand are still in a fall. In light of Chinese growth model decay, the future of demand increase might be in India. At the same time, Indian economy may not count on the same prospects in terms of fuels appetite as compared to Chinese experience, the second global economy.

Iran and potential new entrants

In recent years, events like Libyan civil war and sanctions against Iran's nuclear program had an important impact in the market. By July 2015, Iran, United States, China and the European Union reached an agreement that lifted the ban against Iranian crudes commercialization, which implies that the Islamic country could put back in the marketplace more than one million barrels per day lost since 2012 when sanctions took place. According to some analysts, markets believed Iran production would come up to this production level by mid-2016, an expectation that influences prices in the short term. Besides, it is expected Iran production to increase more than 2 million barrels per day before 2020, given many new projects official announcements after sanctions were lifted. This scenario implies the addition of roughly 600 thousand barrels per day in the first half of 2016, although some forecasts dismiss the country's capacity to allocate its crudes in the international market, limiting its production growth to some –still significant- 400 thousand barrels per day in the short term. Nonetheless, Iran exported an initial crude cargo to Europe the same month sanctions were lifted and has announced private investment terms easing.

Very close to Iran, Libyan production remains lower than pre-conflict levels which leaves room to production increases after a possible pacification that does not look so far. In addition, Iraq could recover its production after being partially affected by ISIS raid upon the country. In this context, the operating cost advantages of these countries makes the case for all this production entrance without regard of the price level that prevails in the market.

Russia and other non-OPEC producer's status

El grupo de países productores no miembros de la OPEP son particularmente sensibles al desplome Non-OPEC producers are particularly sensitive to oil price slump. In spite of that, they have resisted with a lower-than-expected production decline. Russia, the third world producer reduced its own offer in 200 thousand barrels per day by the end of 2015, after reaching a historical maximum of over 11 million barrels per day six months earlier. In recent days, Russian government announcements revealed the country's aim to enter in negotiations with OPEC members to collude in market interventions. Recently, OPEC and non-OPEC producers finally got in a round of talks intended to agree a freeze in production, with no concrete results to the date. The eventual execution of a production freeze is conditioned to the inclusion of countries like Iran and Iraq. The former has already announced some interest.

Saudis have said the agreement is aimed to balance global production and consumption in order to stabilize prices, not to cause major shifts in production to increase them significantly. Nonetheless, non-OPEC producers situation following the fall in prices, earmarked by high operational costs in most cases, has been the reason behind the drop in active rigs as well as the close of many unprofitable wells.
All of these events, combined with current investment downturn, anticipate future production decreases from non-OPEC producers. The group includes Russia, Brazil, Mexico, Norway and others which represent more than 50% of global production. The offer coming from all these countries has been declining and other 660 thousand barrels per day are expected to be out of the market by the end of 2016. New market situation reduces share to these producers with no relevant market power alone, even more after the decline on its oil market share.

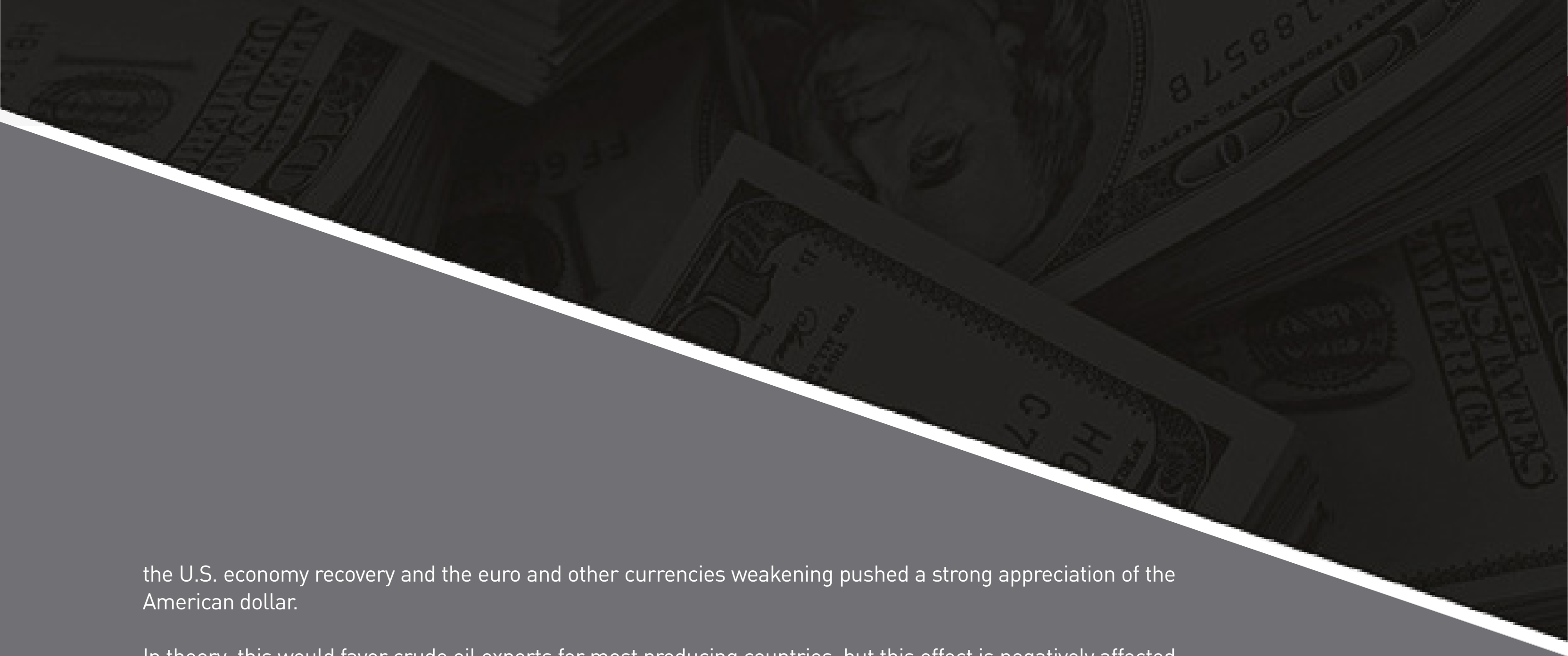
Inventory gains

Elevated production levels without sufficient demand to offset caused crude oil inventories to grow around the world. Booming shale production in the United States contributed to accumulate inventory until contingency and, in some cases, emergency levels. The recent building of facilities in Corpus Christi, Texas, has increased total storage capacity significantly in face of growing production. According to the IEA, inventories in the United States have grown up until 500 million barrels in September 2015 of which, added to another 3 thousand million barrels in OECD countries, represent 31 days of cumulative global oil demand. Other strategic inventory investments have been projected in countries like China, where the government has announced recently other 600 thousand barrels storage facilities addition. This would mean to increase its imports coverage from the current 30 to over 90 days in the future, according to Reuters.

In this sense, China would be taking advantage from international low oil prices to increase strategic reserves in favor of its long term energy security. At the same time, the global storage space downsizing could add some additional barrels to the global supply in the short term, as long as the investments on its expansion become tangible, pressing prices down.

Dollar appreciation and interest rates increase

The global financial crisis triggered a large amount of liquidity injection to the international financial system by the Federal Reserve. The U.S. central bank reduced interest rates to levels near to zero and has bought U.S. treasuries massively in order to flood financial markets of cheap money to encourage credit and economic growth. All of these policy measures are the main cause of the dollar depreciation since 2009 until 2014, when



the U.S. economy recovery and the euro and other currencies weakening pushed a strong appreciation of the American dollar.

In theory, this would favor crude oil exports for most producing countries, but this effect is negatively affected by recent price slump. In terms of international oil prices, as calculated in U.S. dollars, the currency appreciation pushes down prices since buyers expect to compensate the higher exchange costs by reducing even more the commodity price.

The oil has lost value in the market, but the currency obtained in exchange have increased its value. Finally, interest rates hike executed recently by the Federal Reserve has affected oil industry projects with high operating costs severely, making them even less profitable after the price slump. This fact has caused the reverse of 60% of new drilling projects in the U.S., from where most of production increases have come from. Besides, the recent interest rates hike deepen the dollar revaluation and implies the end of low cost liquidity access in international financial markets for oil and gas business. This process could evolve even more since the dollar is expected to appreciate further in 2016 and 2017.

Futures markets and prices expectations

Oil is a financial asset traded in futures markets with speculative ends, and negotiated in physical deliver in future and spot markets. Future markets have turned into a reference when it comes to market prices references, not only for oil but for all kind of commodities.

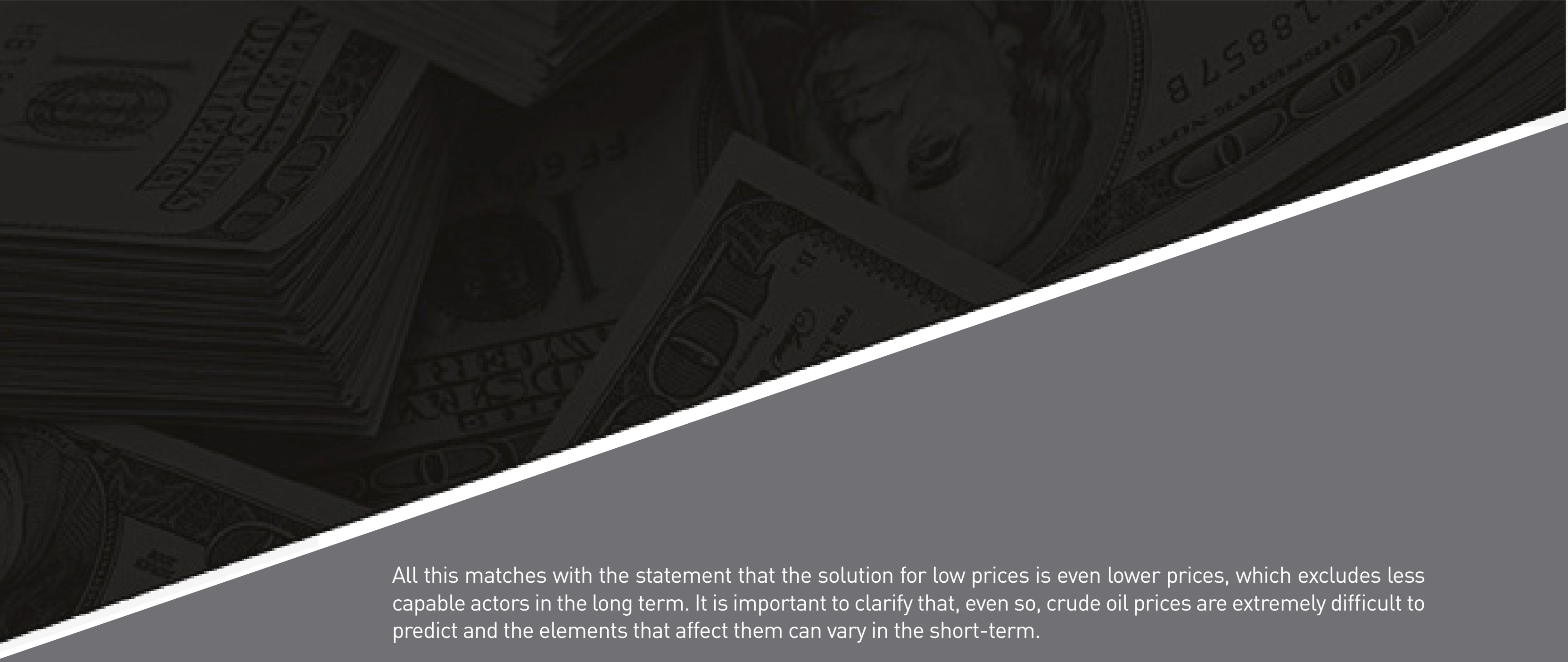
When futures prices are above expected spot prices occurs the so-called contango phenomenon, in which the market expects the future price to rise. Contango is happening since the end of 2014, which means the market expects that current supply is more than future supply and prices slump will eventually reach a limit, with a hike in the medium term. The opposite phenomenon -known as backwardation- was happening from July to November 2014, when the trend changed. For this reason, many speculators were storing crude and contributing to the inventory buildup in the short term. All these fundamentals match with many analysts and agencies projections which account on a price hike by the end of 2016.

From the last quarter of 2015 and during all of 2016, projections have been falling too, pressing oil futures prices downward. These expectations about future prices are relevant since the market –in a transition period– are eager to get new information.

Global over glut and consequences for crude oil prices

In short, global oil supply is far over demand. This difference has been growing in recent years, hence prices have been decreasing. According to the OPEC, global oil demand reached 92.9 million barrels per day during 2015, while supply was 94.9 million. Since 2014, the difference between both grew by 1 million barrels per day, and it could grow other 1.3 million barrels per day in 2016.

Traditionally, an OPEC-style intervention aimed to stabilize the market could be expected. Nonetheless, Saudi's reluctance to reduce its own production has forced other producers to adjust. Under this assumption, crude oil supply will be more efficient and prices will not reach again the 100 dollars barrier per barrel. In fact, most projections in the long term set a range of 40 to 70 dollars per barrel.



All this matches with the statement that the solution for low prices is even lower prices, which excludes less capable actors in the long term. It is important to clarify that, even so, crude oil prices are extremely difficult to predict and the elements that affect them can vary in the short-term.

Under this structural change in the oil market, Venezuela has to adapt and develop a better strategy over the long term. Waiting for a price recovery in the short term is a risky and costly bet. Given the internal and external imbalances of the Venezuelan economy, including huge fiscal and external deficits, an oil price increase would not deliver any sustainable solution to the current crisis. Economic and energy policies must be coordinated in order to stabilize the economy and correct these imbalances, as well as to recover lost spaces in the market, through better management practices in the national oil industry. Ultimately, a price hike will not mean a solution and remains a hardly predictable and implausible fact.

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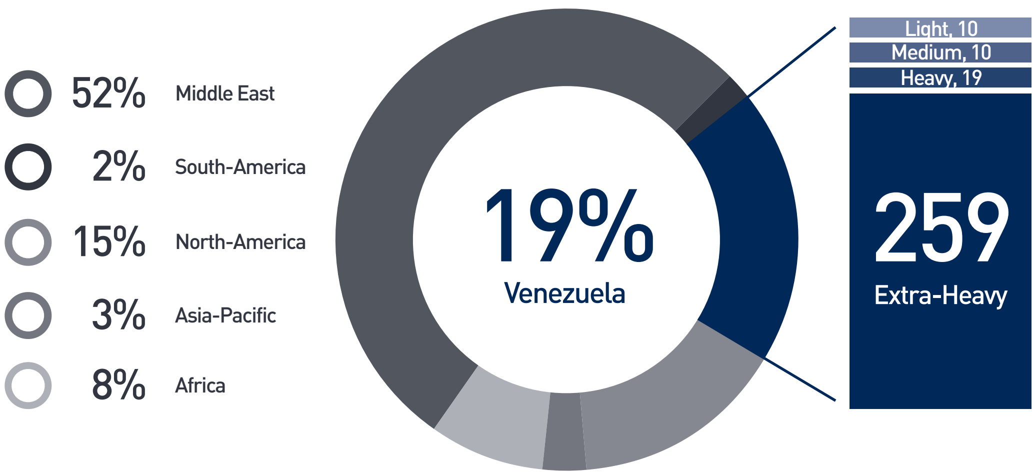
Exploration and production

RESERVES IN 2015

According to official figures, Venezuela accounts for 19% of total world oil reserves, 90% of South-American reserves and 53% of total American reserves. Most of the country's oil in ground is classified as extra-heavy, which represents 259 billion barrels out of 298 billion barrels, or 86% of total reserves.

Figure 4 World and Venezuela oil reserves (2015, billion barrels)



Source: Statistical Review of World Energy (BP, 2015), Annual Management Report 2015 (PDVSA, 2016).

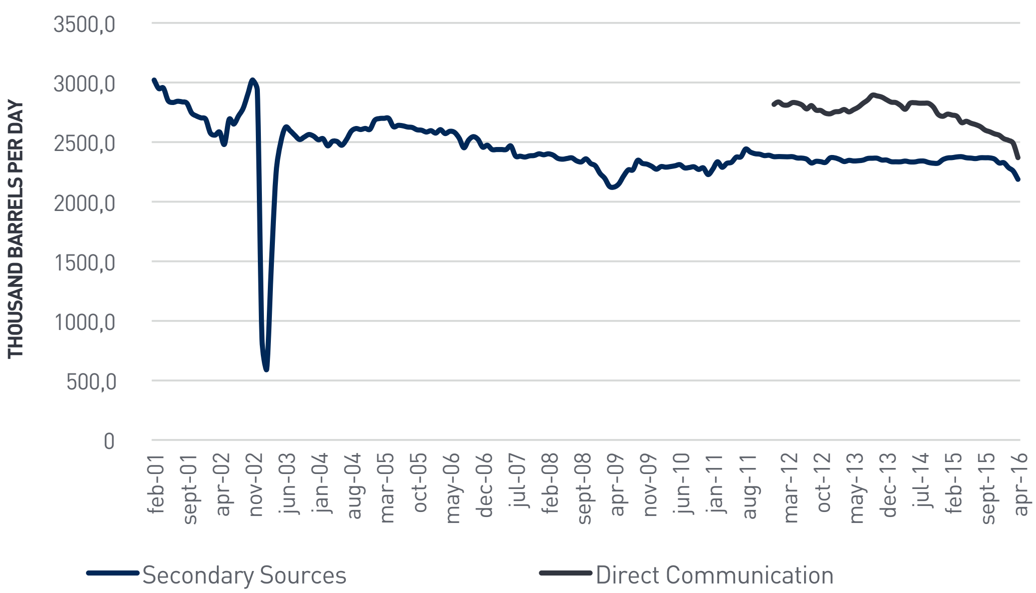
PRODUCTION

Venezuelan official figures and international sources on oil production consider liquids condensates and natural gas associate liquids in their calculations. According to BP Statistical Review of World Energy 2015, Venezuelan production amounts to 2.719 tbd, an increase of 1.2% as compared to 2013 figure. However, PDVSA's Annual Management Report (2014) reports 2.785 tbd, a 3.9% decrease from 2013.

OPEC figures do not take into account the hydrocarbons mentioned earlier: the organization reports a crude oil production during 2014 of 2.373 tbd according to secondary sources and 2.683 tbd as reported by government.

Overlooking the source of information, Venezuelan oil production has been declining during the last decade. The trend deteriorated more since the drop in June 2016 of 120 tbd in monthly oil output.

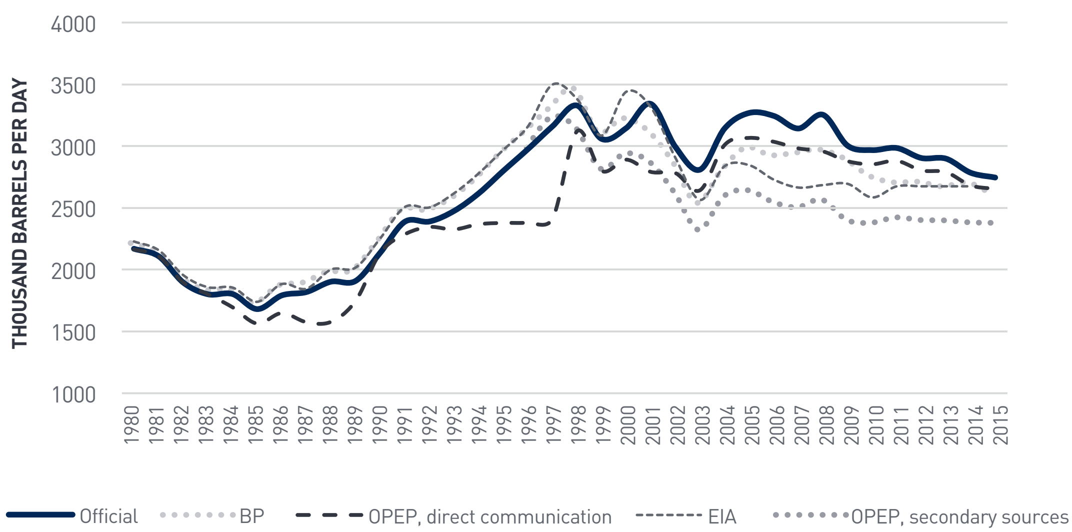
Figure 5 Venezuelan oil production as reported by OPEC (February 2001 - May 2016).



Source: Monthly Oil Market Report (OPEP, various years)[1]

[1] Since 2001, OPEC has published member countries production according to secondary sources. Since 2011, OPEC reports include member countries direct communication figures on production.

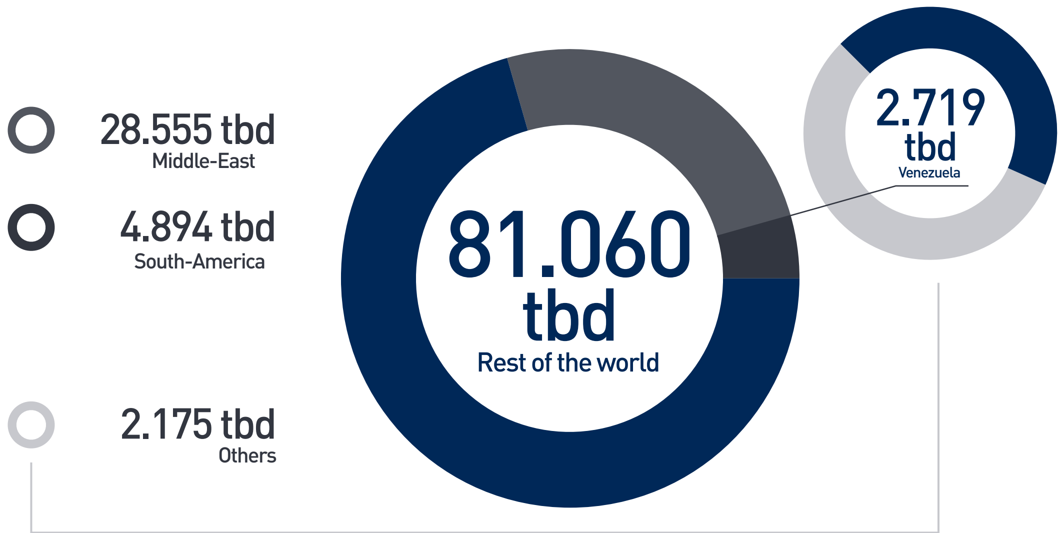
Figure 6 Venezuelan oil production by source



Source: PDVSA Annual Management Report (2015), PODE (MENPET, 2012), Statistical Review of World Energy (BP, 2015), Annual Statistical Bulletin (OPEP, 2015), Annual Report (OPEP, 2015), International Energy Statistics (EIA, 2016) [1]

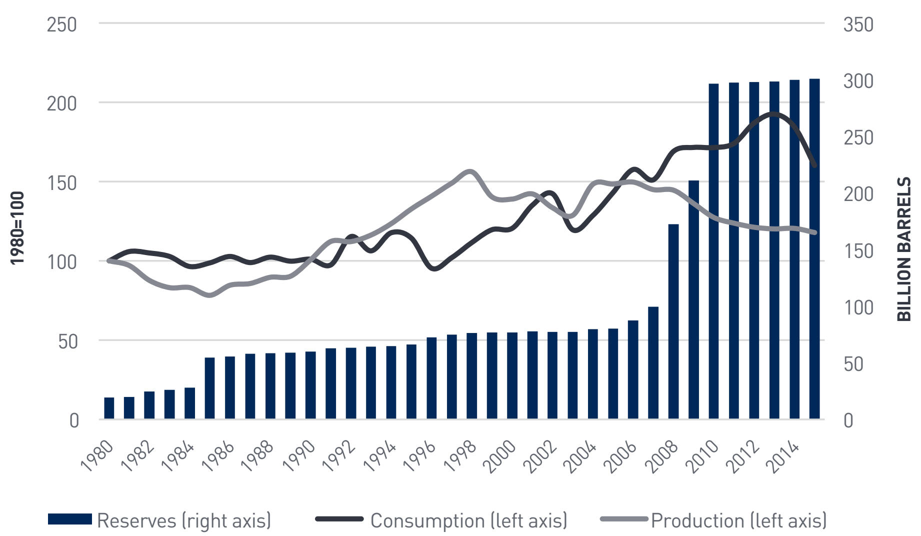
[1] Between 1980 and 2012, official data correspond to crude oil production as reported by MENPET (2012) and since 2012 as reported by PDVSA (2016). BP (2016) corresponds to crude oil production. OPEC, (2015) corresponds to crude oil average production. EIA (2016) reports crude and liquids production until 2014.

Figure 7 World oil production (2015)



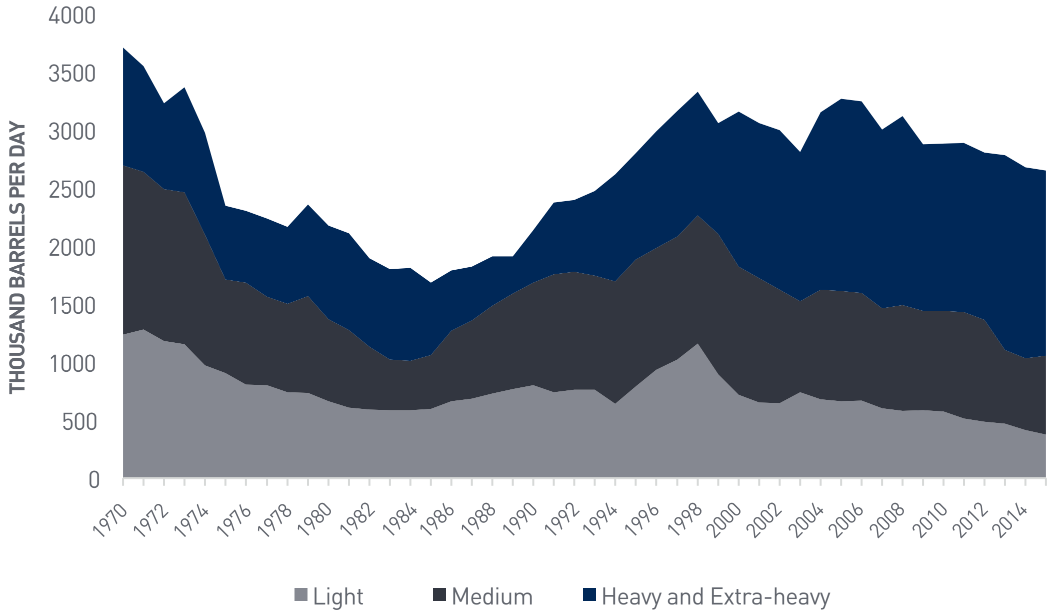
Source: Statistical Review of World Energy (BP, 2015)

Figure 8 Reserves, production and domestic consumption (1980-2014)



Source: Statistical Review of World Energy (BP, 2016) and CIEA.

Figure 9 Crude oil production classified by API gravity (1970-2014)



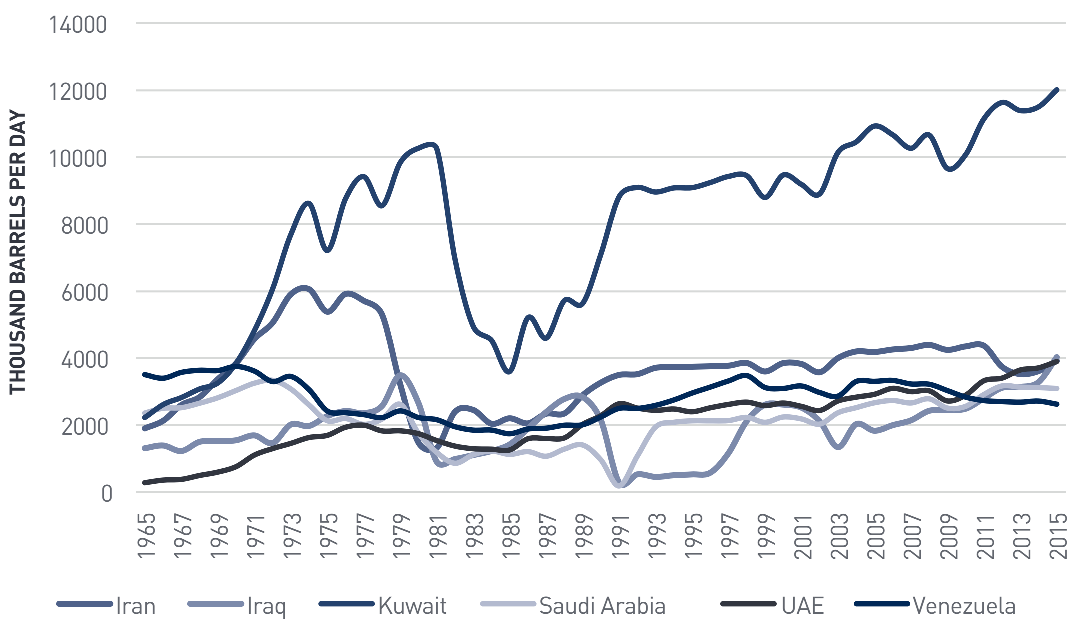
Source: PODE (MENPET, 2012) and Annual Management Report 2015 (PDVSA, 2016).

Since 1997 Venezuela shows this declining trend in total oil production which is persistent for light and medium type crudes. Both amounted a total output of 416 tbd and 619 tbd as of 2014, respectively. Heavy and extra-heavy oil production reached 1.640 tbd in the same year. As a result, 61% of national production is composed of heavy and extra-heavy crudes, with a tendency to concentrate the national crudes mix in these categories.

VENEZUELA AND THE OPEC

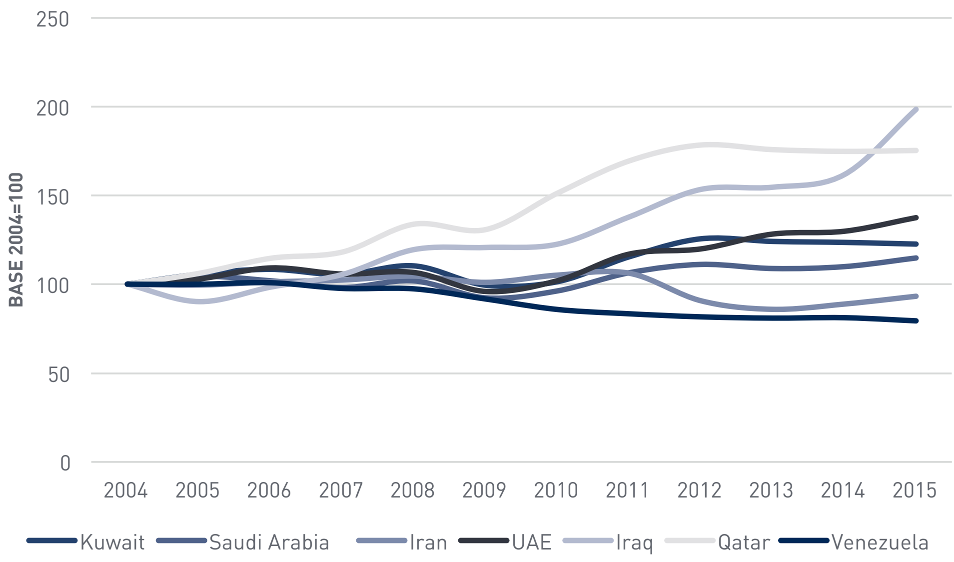
When compared to other OPEC members, Venezuela has underperformed Qatar, Iraq, United Arab Emirates and Saudi Arabia in terms of production growth since 2004. Similarly this is the case for America's major producers, where Colombia, Brazil and the U.S. are responsible for most of the growth in total production, outperforming Venezuela's decreasing figures. Nonetheless, recent price environment has slowed down unconventional crudes production in North America, particularly between 2014 and 2015.

Figure 10 OPEC members production



Source: Statistical Review of World Energy (BP, 2015).

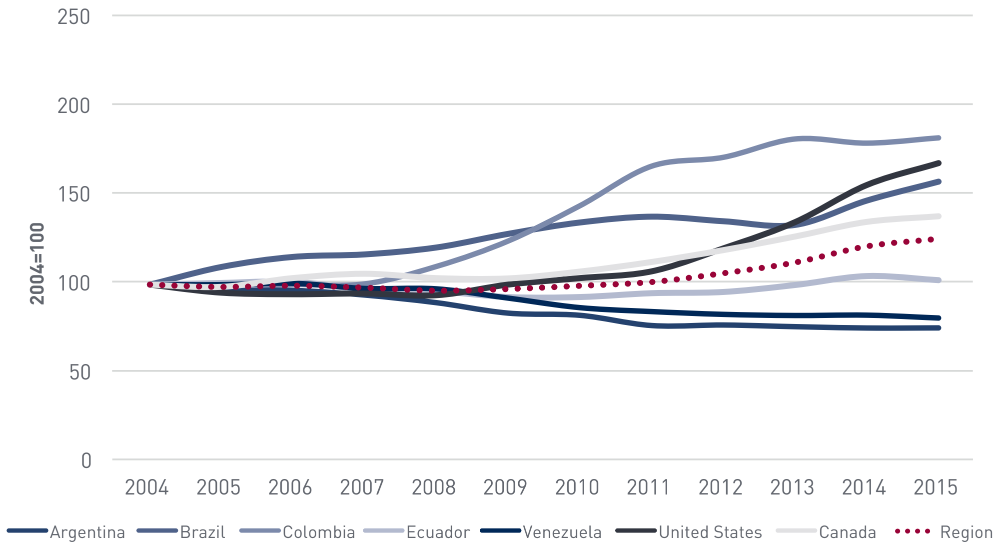
Figure 11 Compared production: Venezuela and other OPEC members (2004=100)



Source: Statistical Review of World Energy (BP, 2015) and CIEA

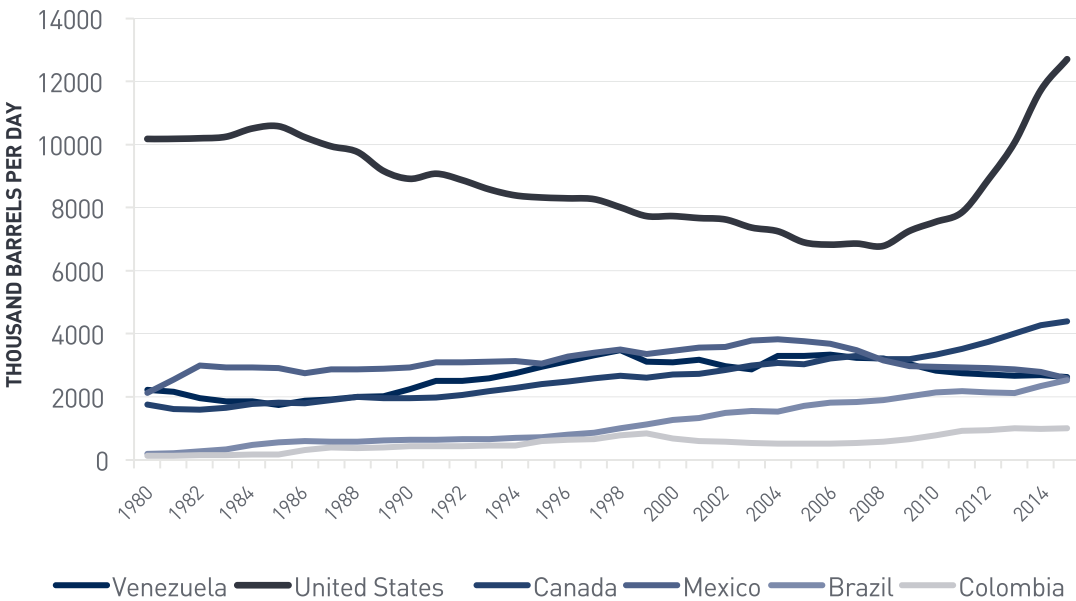
VENEZUELA AND THE AMERICAS

Figure 12 Compared production: Venezuela, South and North America (base 2004=100)



Source: Statistical Review of World Energy (BP, 2015) and CIEA

Figure 13 The Americas: Crude oil production (1980-2014)



Source: Statistical Review of World Energy (BP, 2015)

BOX

/2

WHY VENEZUELA IMPORTS OIL FROM THE UNITED STATES?

- BY ARMANDO ROMERO -

Lately, PDVSA has been buying West Texas Intermediate crude from the U.S., starting with a purchase of 500 thousand barrels in February 2016.This acquisition made Venezuela, once the first oil exporter in the world, the first country in Latin America to import U.S. crude oil after the export ban lifting, which was effective in January. Nonetheless, it is not the first time that PDVSA seeks international suppliers in order to access light crudes and other inputs which were produced by the industry before. As recent history shows, hydrocarbon imports aimed to provide feedstock for operations have turned into a requirement in order to place local production in international markets.

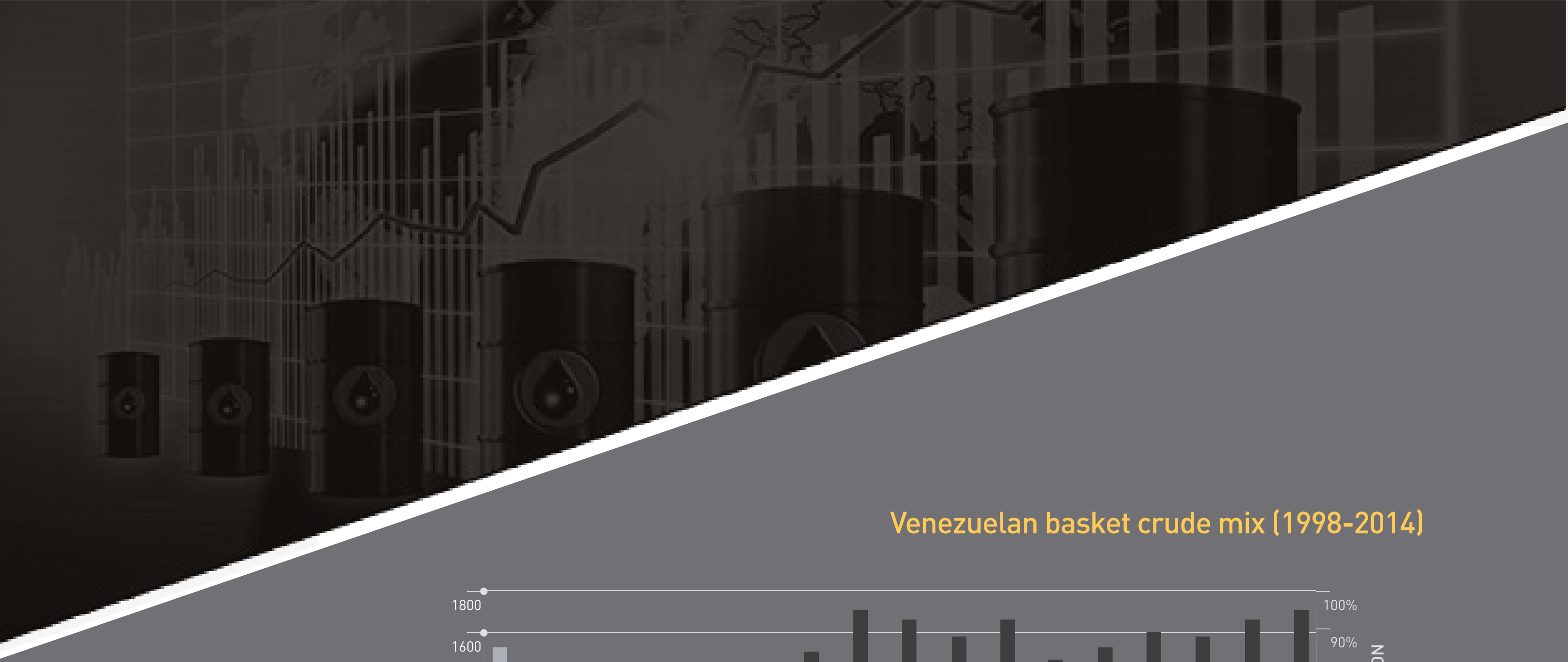
Even though Venezuela has the largest oil reserves in the world, most of them are composed of heavy and extra-heavy crudes, which require additional processes and inputs to make them marketable. In the last decade, the production of these kind of crudes has been growing fast while the lighter ones has declined. This pattern has been fueled by strong investments in E&P, upgraders and other kind of facilities in the Orinoco Oil Belt, where the biggest share of heavy crudes is located. Consequently, the entire profile of the Venezuelan oil basket has been modified in recent years.

DCO vs. Upgraders

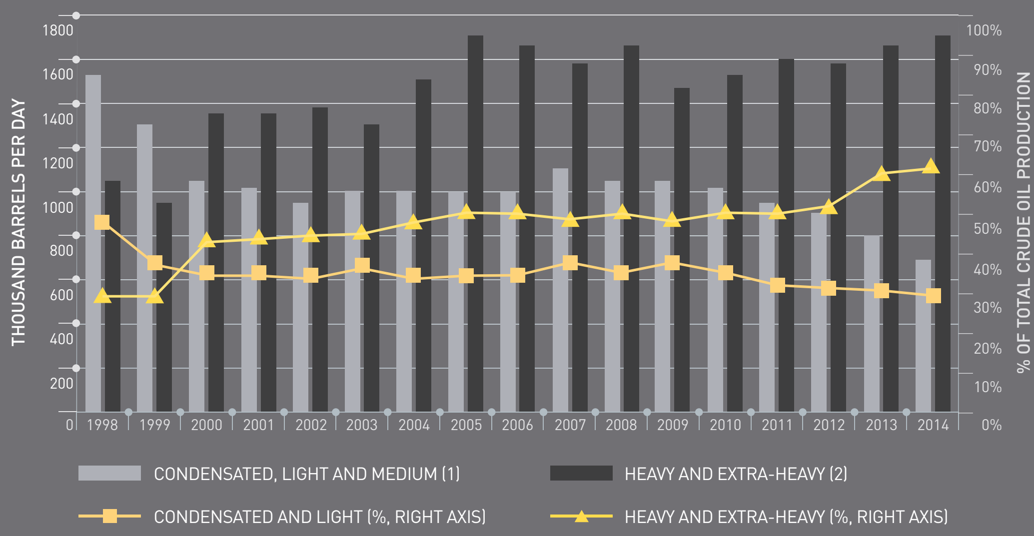
After being extracted heavy and extra heavy crude oil can go either to upgraders or can be transformed into Diluted Crude Oil, before being exported. In both cases, the goal is to get a lighter crude which can be easier to transport and commercialize.

The construction of upgrading facilities requires substantial investments in highly specialized machinery which extracts the heavy content of the crude and minimizes the use of diluents. Venezuela has four of this facilities which process near 500 hundred thousand barrels per day and possess an installed capacity of 630 hundred thousand barrels per day. In order to operate them, PDVSA is associated with Total, Statoil, Chevron and Rosneft. Nevertheless, national upgrading capacity does not cover total heavy and extra-heavy crude oil production, which is over one million barrels per day.

The remaining portion of heavy and extra-heavy crude oil is processed as DCO. They include other light hydrocarbon as diluents: light crude oil and refined products such as light and heavy naphtha. Heavy crude oil production continues to grow importantly, at the same time, light and medium types declines. This in turn causes several operating problems, which are aggravated by the national refining system own operational issues and the stagnation of upgraders capacity.



Venezuelan basket crude mix (1998-2014)



Source: Annual Management Reports (PDVSA, various years) and PODE (MENPET, various years). (1) More than 22° API. (2) Less than 22° API.

Since 1998, condensed, light and medium crude oil production changed its relative share on total production starting from 50% to 27% at the end of 2014. Meanwhile, heavy, extra heavy and upgraded increased their share by 30%, from 32% to 62% during the same period. This represents a complete mutation of Venezuelan production and export basket to a more diluent-dependent mix.

Before the industry began to import inputs, the Mesa 30 Venezuelan crude and local naphtha production could satisfy internal diluent needs in the production of DCO and Merey 16 (a heavy Venezuelan crude). Starting in 2014, the upgrade facilities reached their installed capacity and the amount of lighter crude was in decline, therefore PDVSA had to import in order to allow the growth of heavy crudes production. Initially, PDVSA introduced crudes like Russians Lukoil and Urals, Algerian Saharan Blend, Nigerian Bonny Light and Bonga, Angolan Cabinda and others, as well as heavy imported naphtha to the diluent mix.

Finally, after the recent 40-years-ban lifting, the NOC issued a purchase order of WTI, which price operates as a benchmark globally. This import was the first relevant U.S. crude flow to Latin America since 1970 and the first Venezuelan oil import from that country. Definitely, a major milestone.

At the end of February 2016, PDVSA asked for a new purchase of other 550 thousand barrels of the benchmark crude, which were delivered from Texa's Nederland port by March. Certainly, transport costs related to African and European transactions are higher hence the company is reducing the acquisitions from these locations since January.

How much more diluent will be imported in the foreseeable future?

Considering all the signs, diluent import will remain in the future. Since 2015, PDVSA has been receiving ultra-light crude supply offers in contracts of one to five years. These contract terms reveal the company's purpose to ensure inputs availability to process its own heavy mix in the medium and long term.

Specialized consulting firms, such as Wood Mackenzie, anticipate that imported diluent dependency will intensify in the future as the heavy and extra-heavy crudes production grows. The IEA expects world heavy oil production to double before 2040. For Venezuela that production could triplicate in that period, subject to structural factors and circumstantial developments. This would increase diluent demand from 500 hundred thousand to over 2 million 5 hundred thousand barrels per day in ten years.

Declining light production trend and refining unit's operational struggles raise significant challenges and constraints for the industry. Other bottlenecks in exploration and production, transportation and commercialization narrow import capacity for an industry which is not adapted to it. In recent weeks, there has been a new procedure in which PDVSA is required to make advanced payments in foreign crude purchases after cumulative delays in all kinds of payments to suppliers.

Meanwhile, crude imports are crucial to preserve heavy crude exports, generate additional commercial value to them and get some cash flow in the short term. In light of the severe cash crunch suffered by the economy, the low prices environment and the production decline, allocating foreign currency for inputs imports instead of producing them locally imposes high opportunity costs due to other sector foreign currency needs.

Considering this, PDVSA has asked recently to their OOB partners to finance diluent purchases to produce DCO by they own, even when contractually is responsible for it. The goal is to minimize the use of foreign currency in crude imports by externalizing the cost to third parties, which harms severely the country's attractiveness in the midst of a global investment slowdown.

Even accounting on cost implications, hydrocarbon imports will continue in the future given its relevance to generate new foreign currency in an industry that remains competitive in international markets. Nonetheless, it is important to highlight the role of planning of investments and to ponder diverse operating difficulties and challenges arising from market environment which harm the performance and are worrisome for the immediate future and the long-term growth of the Venezuelan oil industry.

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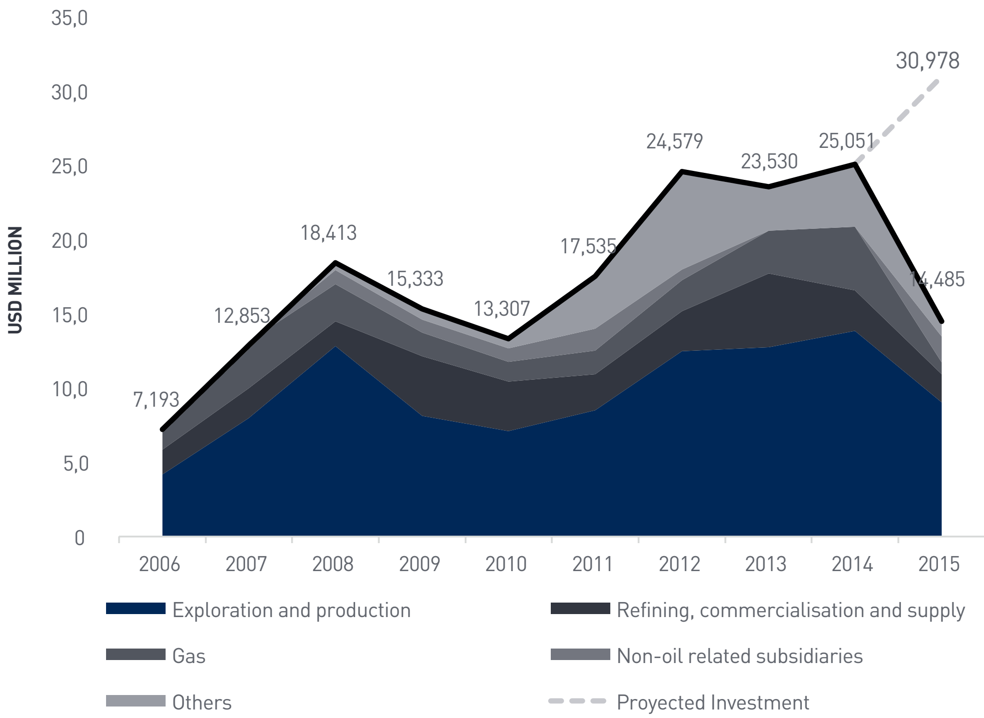
OIL AND GAS INVESTMENT

Total investment disbursements were very close to 25,000 USD million during 2014, which represents a 6% increase since the previous year. Capital expenditure (CAPEX) was composed of the following items: E&P (55%), gas developments (17%), refining, marketing and supply (11%) and others (17%).

PDVSA planned to increase its CAPEX by 27% in 2015 and more than twofold in 2016. Projected total investments in 2015-2019 is highly concentrated in core activities (E&P and refining), and are estimated in 277,000 USD million during this period. However, official figures show a total investment of 14 USD billion in 2015, which represents 36% of planned investment budget and a drop of 42% as compared to 2014.

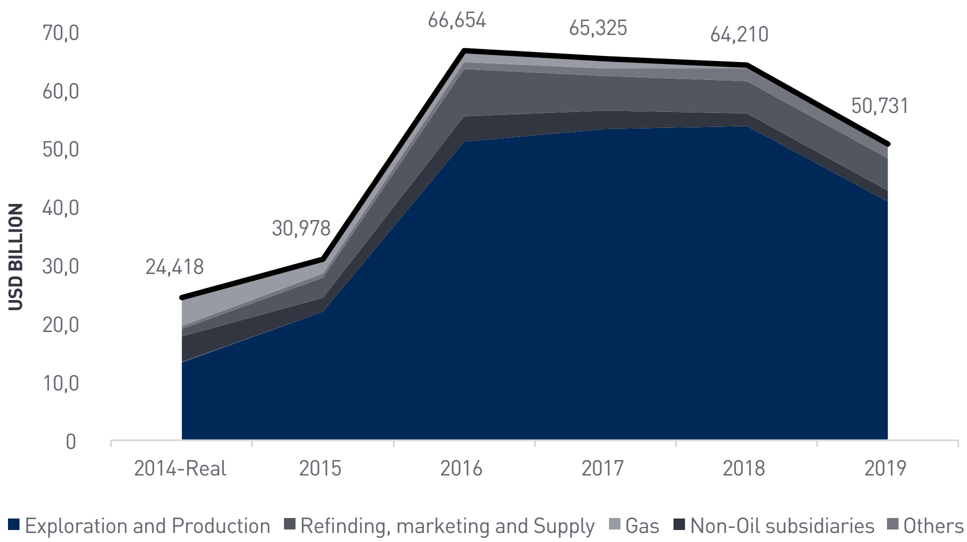
In 2015, most investment cuts occurred in gas development budget, which dropped 81%. Other investments fall 75%, E&P 34% and refining 30%. Meanwhile, E&P remains as the top investment disbursement for PDVSA.

Figure 14 Investment disbursements by type (2006-2015)



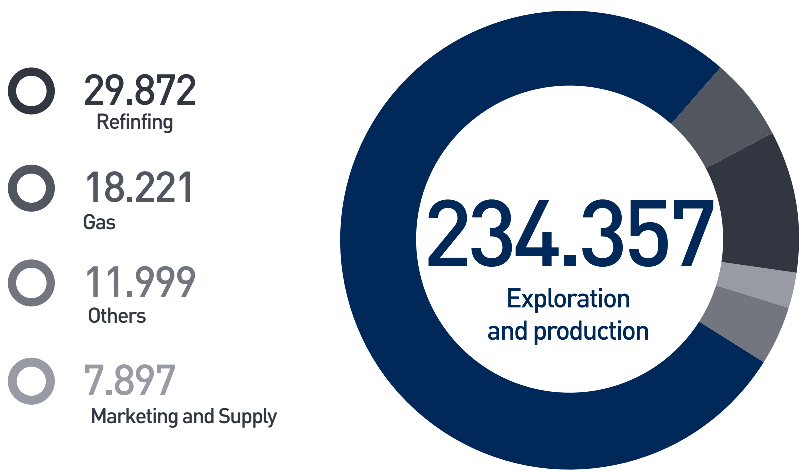
Source: Annual Management Report (PDVSA; 2014, 2015).

Figure 15 Investments projections (2014-2019)



Source: Annual Management Report 2014 (PDVSA, 2015).

Figure 16 Investments projections by type, (2014-2019, USD million)

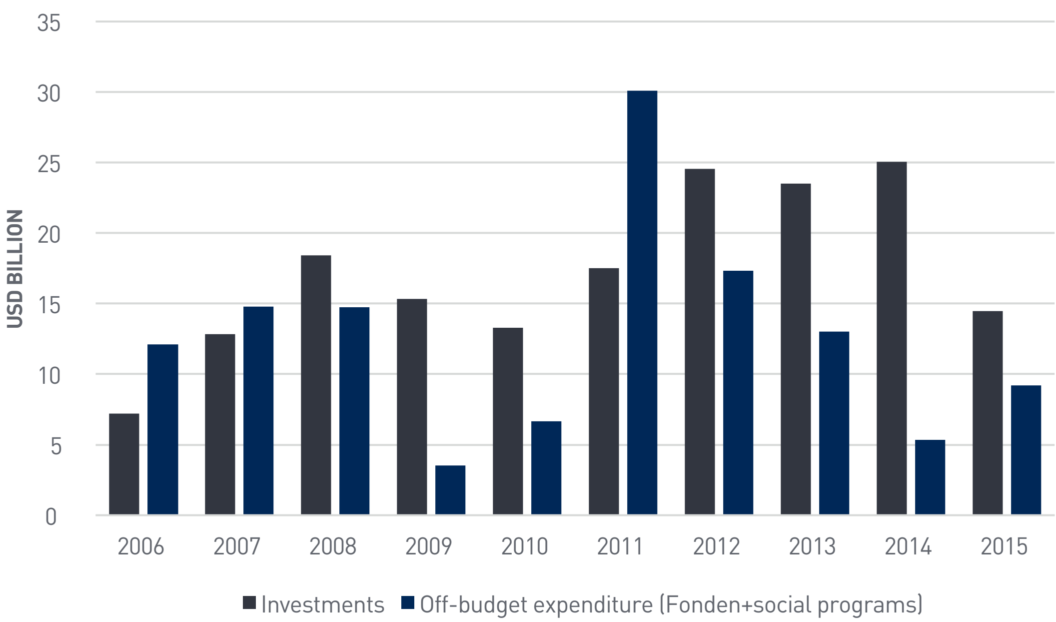


Source: Annual Management Report 2014 (PDVSA, 2015)

INVESTMENTS AND OFF-BUDGET EXPENDITURES

Even when most of PDVSA's investment disbursements in 2014-2015 were allocated into hydrocarbon business related destinations, other expenditures represented a relevant part of finances in recent years, which are earmarked for parallel mechanisms as the state ruled Fondo Nacional para el Desarrollo Endógeno (FONDEN) and social programs known as Misiones Sociales. All of these off-budget expenses have been under discretionary management by the Executive branch[2]. During 2014, off-budget expenditure amounted 5,000 USD million, plunging 59% yoy. Nonetheless, off-budget expenditure grew 73% in 2015, unlike a -42% industry investment variation.

Figure 17 PDVSA: investment and off-budget expenditures (2006-2015)

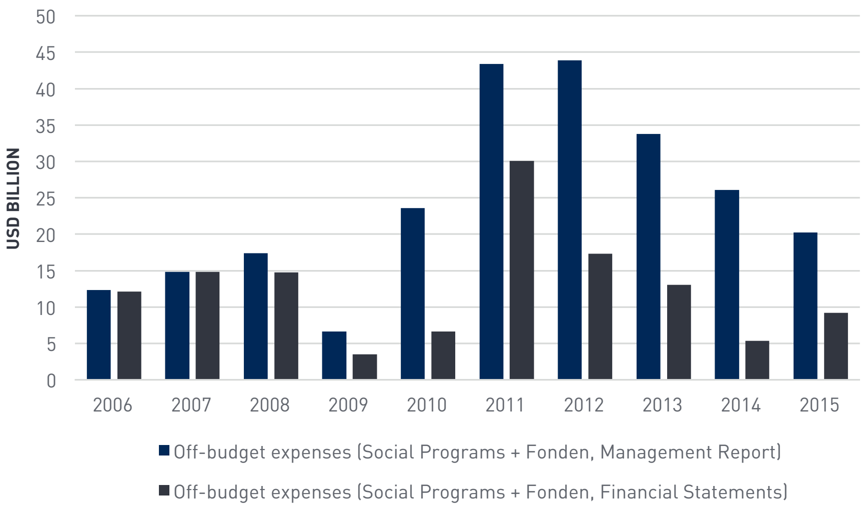


Source: Annual Management Report 2015 (PDVSA, 2016) and CIEA.

PDVSA reports two different figures for off-budget expenses in FONDEN and social programs. The first is published in PDVSA Management Reports and shows all of the amounts assigned to each social program. On the other hand, PDVSA financial statements provide figures with disparities that total 20 USD billion between 2012 and 2014.

[2] See Rodríguez S., Pedro L. and Rodríguez P., Luis R. (2012) El Petróleo como Instrumento de Progreso: una nueva relación Ciudadano-Estado-Petróleo. Caracas: IESA.

Figure 18 Off-budget Expenses: FONDEN and Social Programs (2006-2015)



Source: Annual Management Report 2015 (PDVSA, 2016) and CIEA.

Table 3 Off-budget expenditures: accounting differences in USD million (2006-2015)[1]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fonden (Financial Reports)	6.855	6.761	12.407	577	1.334	14.475	14.994	10.435	8.507	974
Social Programs (Financial Reports)	5.274	7.341	2.326	2.937	5.326	15.604	9.025	7.829	2.015	8.215
Fonden subventions (Financial Reports)	-	-	-	-	-	-	6.683	5.241	5.201	-
Fonden Contributions (Management Reports)	6.855	6.761	12.384	600	1.334	14.728	15.572	10.418	10.400	976
Fondespa (Management Reports)	229	-	-	-	-	-	-	-	-	-
Social Programs (Management Reports)	5.264	8.048	4.990	6.006	22.223	28.657	28.293	23.341	15.681	19.241
Fonden Differences	-	-	23	-23	-	-253	-578	17	-1.893	-2
Net Fonden Differences	-	-	23	-23	-	-253	-7.261	-5.224	-7.094	-2
Social Programs Differences	10	-707	-2.664	-3.069	-16.897	-13.053	-19.268	-15.512	-13.666	-11.026
Total Off-budget differences	-219	-707	-2.641	-3.092	-6.897	-3.306	-6.529	-20.736	-20.760	-11.028

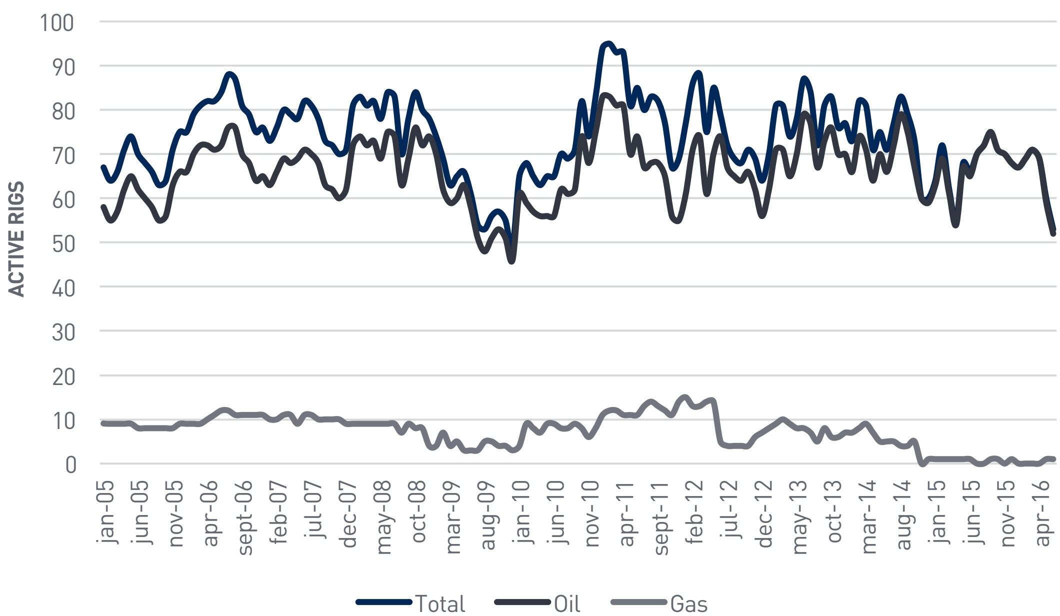
Source: Annual Management Report 2015 (PDVSA, 2016).
[1] Negative differences favor Financial Reports

OPERATING RIGS AND DRILLING ACTIVITY

Total rig count is correlated to total production in the short and long term. For that reason, drilling activity is a good measure of investment and effectiveness in E&P. As of December 2014, Baker Hughes reported a total of 60 active rigs in Venezuela, 9 off-shore and only 1 being related to gas production.

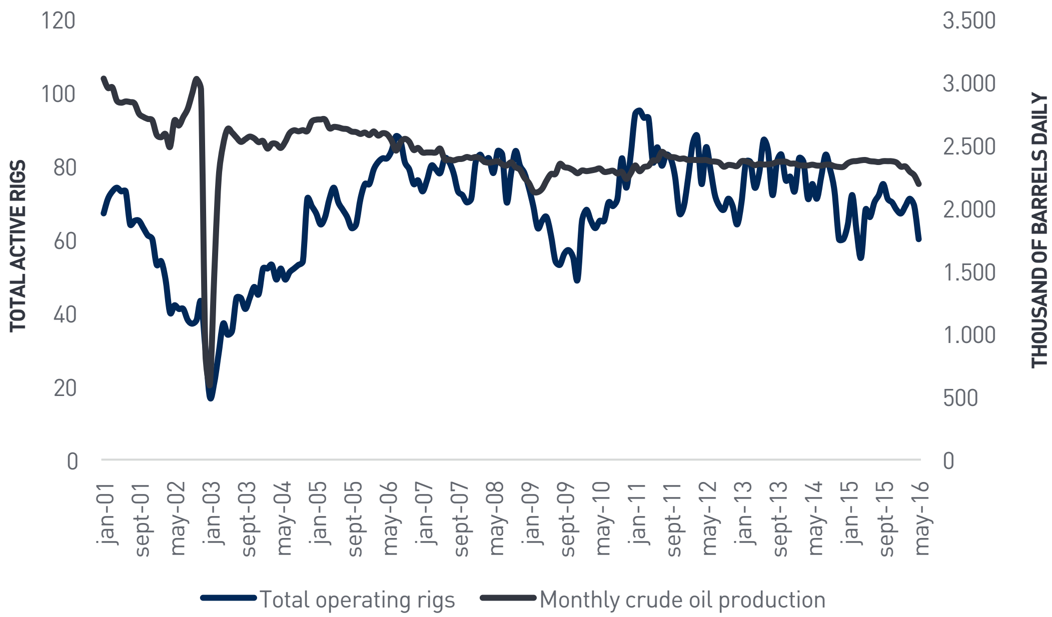
Rig activity has been quite volatile during 2005-2015 in the country, with a maximum of 95 active rigs and a minimum of 49 in that period. Since 1982, maximum rig count has been 119, achieved in 1982. Recent developments show a declining trend in drilling activity, displaying a lack of effectiveness in investments to rebound total crude oil production.

Figure 19 Oil and gas operating rigs in Venezuela (January-2005, April -2016)



Source: International Rotary Rig Count (Baker Hughes, 2016).

Figure 20 Venezuela: Operating Rigs and Crude Production (February-2001, May-2016)



Source: International Rotary Rig Count (Baker Hughes, 2016), Monthly Oil Market (OPEC, 2016).

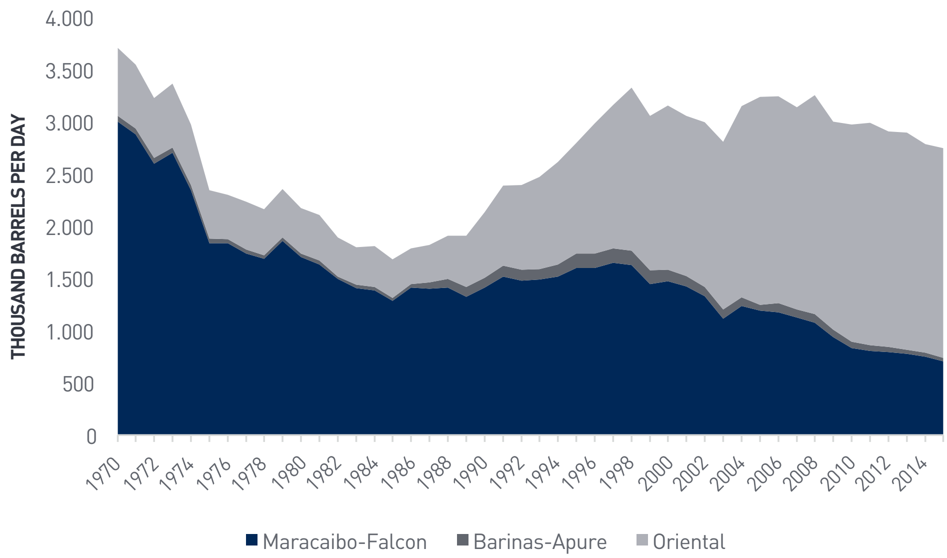
PRODUCTION BY TYPE OF SCHEME

PDVSA accounts on a crude oil production of 2,785 tbd in 2014 and 2,746 tbd in 2015 an annualized drop of 3.9% and 1.4% respectively.

National production achieved 2,899 tbd, including 93 tbd in condensates and 114 tbd of natural gas. PDVSA direct managed production was 1,639 tbd in 2014, a 7.6% contraction since 2013, mostly concentrated in the Eastern basin. In 2014, PDVSA made changes to the Executive Directions Structure by adding "New Orinoco Belt (OOB) Developments" and "Off-shore" (currently managed by JVs). Altogether, JVs reached 1,146 tbd in crude oil production and 1,202 tbd the next year. In 2015, PDVSA managed production declined by 5.8% and amounted 1,544 tbd.

A detailed analysis of the production by scheme evidences the increase of the JVs in national crude oil production. Meanwhile, PDVSA direct managed production plunges at the same time that JVs production has been rising, with an historical peak in 2015

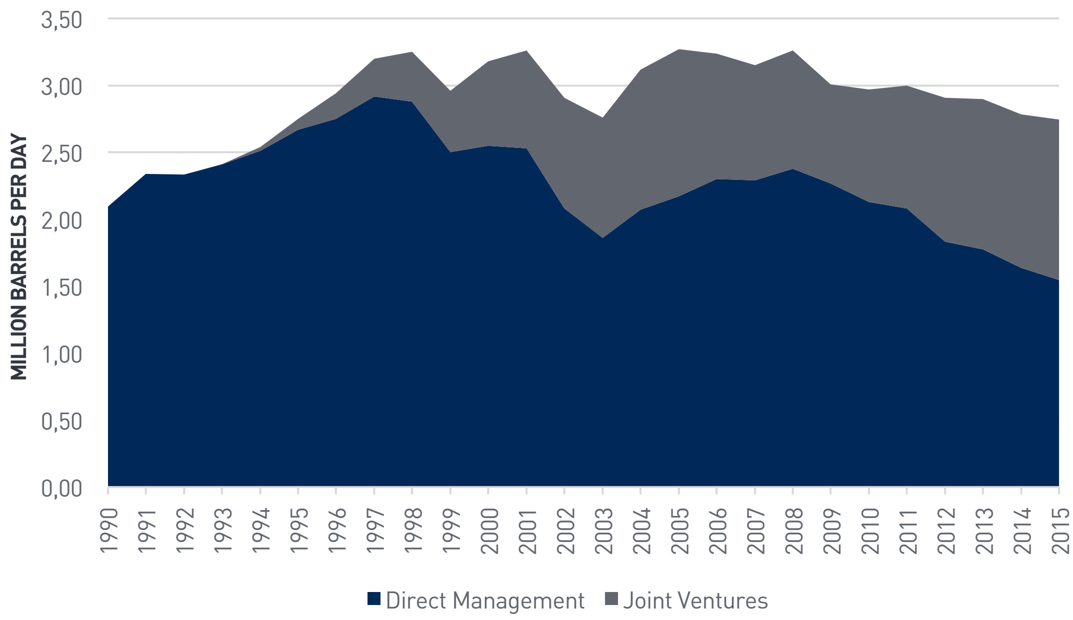
Figure 21 Total crude oil production by basin (1970-2014)



Source: PODE (MENPET, 2012) and Annual Management Report 2015 (PDVSA, 2016).

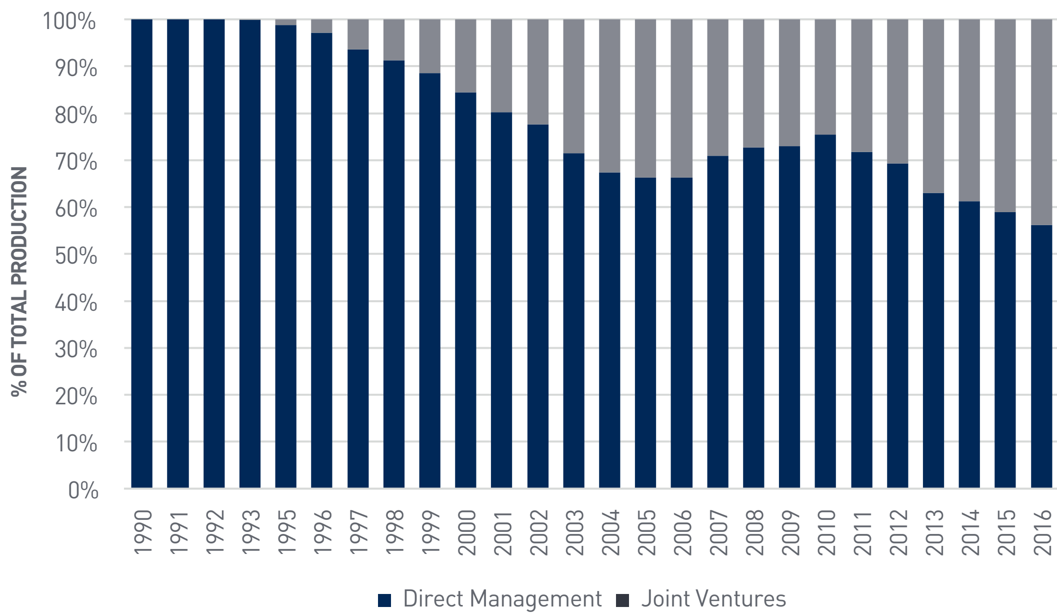
Between the years 1993 and 1997, Venezuelan authorities formalize the Strategic Associations and include private capital companies into the developments of the Orinoco Oil Belt (OOB) area. Four Strategic Associations were created in this period: Sincor, Petrozuata, Ameriven and Cerro Negro. In 2005, every existing arrangements in the sector migrated to new contracts denominated "Empresas Mixtas" or Joint Ventures (JVs).

Figure 22 Production by type of scheme (1990-2015)



Source: Annual Management Report 2015 (PDVSA, 2016) and CIEA

Figure 23 Production by type of scheme as % of total (1990-2016)



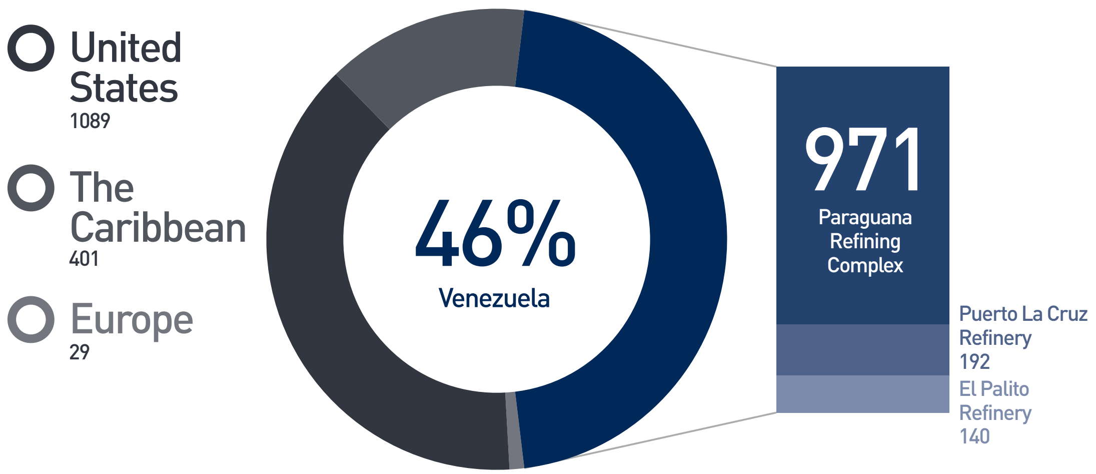
Source: Annual Management Report 2015 (PDVSA, 2016) and CIEA.

Refining

REFINING CAPACITY

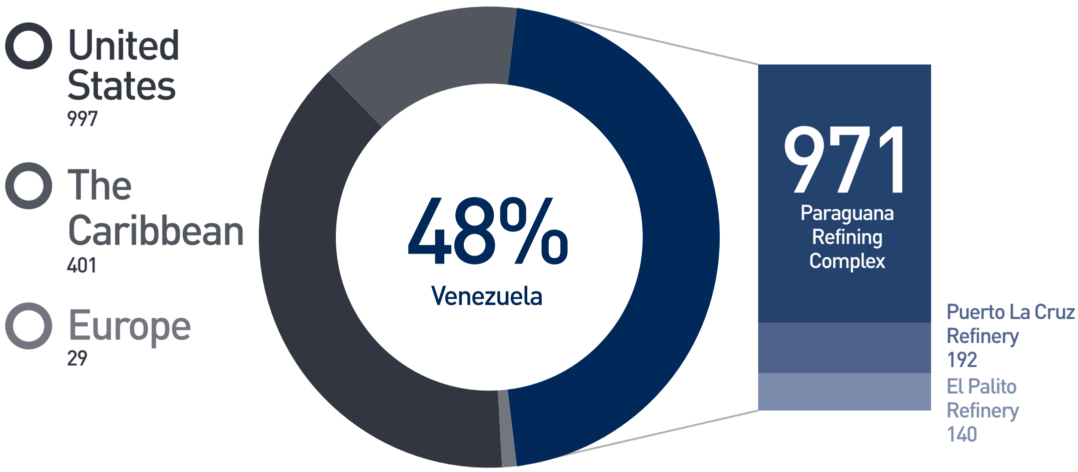
National refining capacity remained unchanged in the last two years. Domestic refining complexes still represent over 45% out of total installed capacity. Also, refining assets abroad were reduced substantially after the Chalmette's refinery sale-off

Figure 24 total refining capacity, PDVSA (2014, tbd)



Source: Annual Management Report 2014 (PDVSA, 2015).

Figure 25 Total Refining Capacity, PDVSA (2015, tbd)



Source: Annual Management Report 2015 (PDVSA, 2016).

Table 4 PDVSA Refineries outside Venezuela (2014-2015)

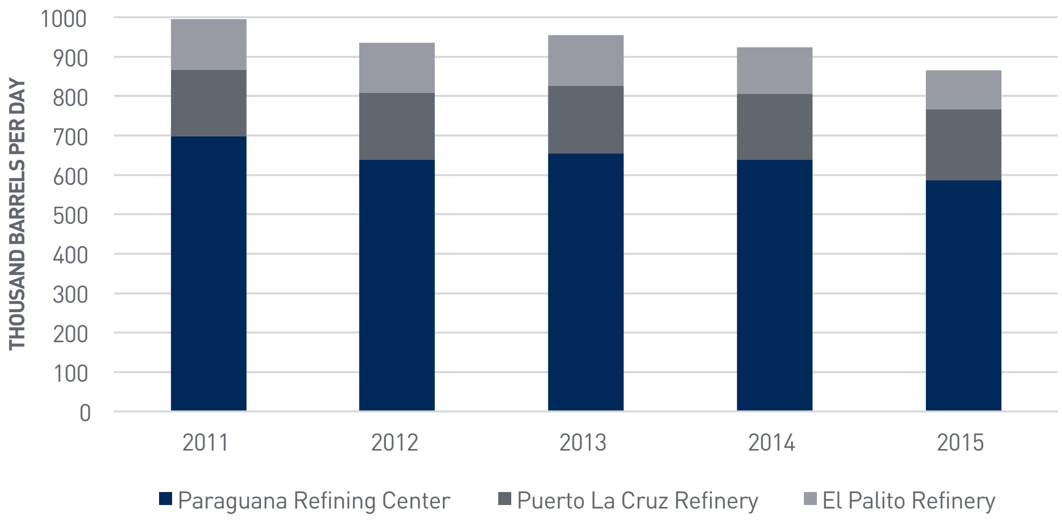
Refinery	Location	Owner	Partner	Refining Capacity (MBD)	PDVSA's Refining Capacity (MBD)	Share
Lake Charles	United States	CITGO		425	425	100%
Corpus Christi	United States	CITGO		157	157	100%
Lemont	United States	CITGO		167	167	100%
Chalmette[1]	United States	Chalmette Refining	Exxon Mobil Co.	184	92	50%
Saint Croix[2]	United States	Hovensa(7)	Hess Co.	495	248	50%
Sweeny[3]	United States	PDV Sweeny	Conoco Phillips*			50%
Camilo Cienfuegos[4]	Cuba	CUVENPETROL	Comercial Cupet S.A.	65	32	49%
Jamaica	Jamaica	Petrojam	Petroleum Corporation of Jamaica	35	17	100%
Isla	Curacao	PDVSA		335	335	100%
Haina	Dominican Republic	Refidomsa PDVSA	Refidomsa	34	17	100%
Dundee	Scotland	Nynas	Neste Oil AB	9	4	50%
Eastham	England	Nynas	Neste Oil AB	18	5	25%
Nynashamn	Sweden	Nynas	Neste Oil AB	29	15	50%
Gothenburg	Sweden	Nynas	Neste Oil AB	11	5	50%

Source: Annual Management Report 2014 and 2015 (PDVSA; 2015, 2016).
[1] Sold in 2015.
[2] JV with HessCo. No PDVSA.
[3] JV with ConocoPhillips.
[4] Closed in 2012, operates as storage facility.

Total refining capacity of PDVSA abroad rises to 1,300 tbd, in which CITGO assets represent 58% with 749 tbd. Chalmette refinery sell-off reduced PDVSA capacity abroad by 92 tbd in 2015.

NATIONAL REFINING

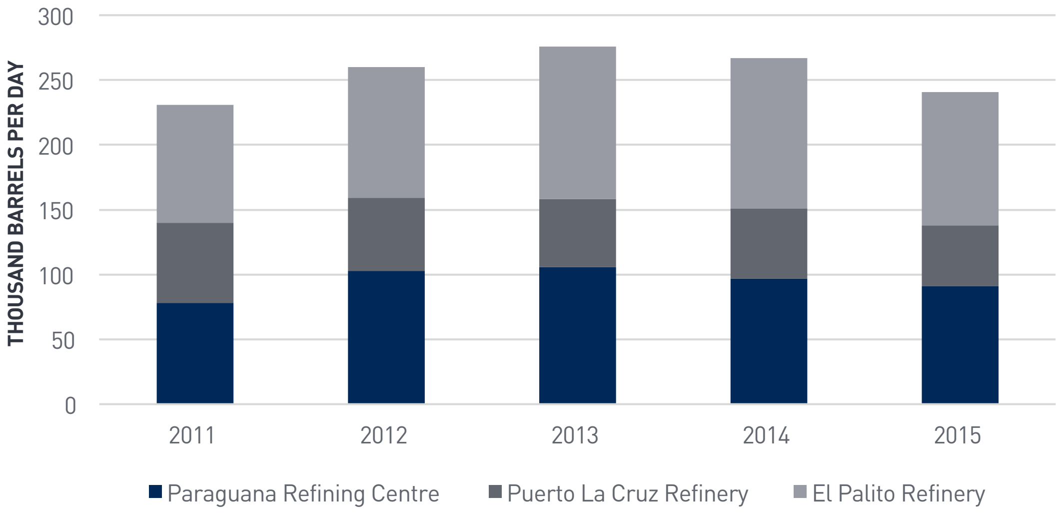
Figure 26 Processed oil volume in domestic refineries (2011-2015)



Source: Annual Management Report 2015 (PDVSA, 2016).

Total processed volume in national refineries has been falling steadily since 2013. Declining crude oil production, particularly light crudes, as well as several operating difficulties have reduced refining activity during these period. Cumulative drop roses 13% since 2011.

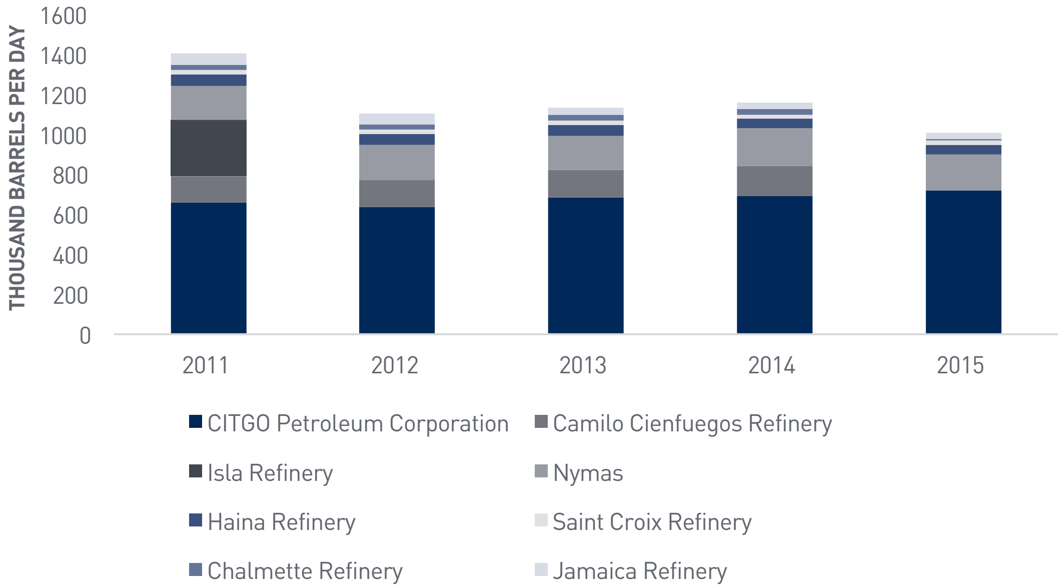
Figure 27 Inputs directed toward processes and mixtures (2011-2015)



Source: Annual Management Report 2015 (PDVSA, 2016).

INTERNATIONAL REFINING

Figure 28 Processed oil volume in international refineries (2011-2015)



Source: Annual Management Report 2015 (PDVSA, 2016).

Chalmette sell-off reduced significantly the processed volume in international refineries to a record low. The Saint-Croix refinery was unincorporated in 2011, this is the second refining asset withdrawal in six years. Even when CITGO refineries and Isla refinery had a slight growth, Caribbean refineries reduced their operation.

BOX /3

ON THE CHALMETTE PDVSA REFINERY SELL-OFF

- BY IGOR HERNÁNDEZ & ARMANDO FLORES -

In the morning of June 18 2015, it was known that PBF Energy, one of the most important refiners in the U.S., would buy Chalmette refinery, a joint property of ExxonMobil (50%) and PDVSA (50%) located in Louisiana. The deal included the transfer of transport and storage facilities associated to its operations and was closed by the end of the year.
There are many unclear issues about the transaction. However, it is important to know the origin, history and current role of Chalmette refinery inside PDVSA's main external assets in order to evaluate the impact of this sale.

1. 1997: PDVSA acquires a stake in Chalmette Refining. In line with the company internationalization strategy that started a decade before, PDVSA bought shares in the refinery in 1997. The objective of the purchase was to assure the placement of Venezuelan crude oils coming from Cerro Negro JV in the Orinoco Oil Belt, where PDVSA had a partnership with ExxonMobil and VebaOel, known as the Strategic Associations.
Chalmette's own properties made it an ideal asset to this end: located in the main Venezuelan oil exports destination in the period (U.S.), it counts with a total processing capacity of 184 tbd and two distillation units: one for light crudes and other for upgraded heavy crudes.

2. What happened in 2008? PDVSA held supply agreements of over 90 tbd with ExxonMobil until 2008 which were expected to be maintained during the partnership.
Nonetheless, the change in the regime from Strategic Associations to Mixed Enterprises –a new JV agreement which in practice meant the expropriation of ExxonMobil assets in Venezuela– motivated its departure from the country and the introduction of international arbitration claims that, in this particular case, resulted in a judgment from ICSID in 2014 which commands PDVSA to pay 1.6 USD billion in compensation to the IOC.
From then on, Chalmette refinery registered a decreasing supply of crude from Venezuela, in the middle of objections from Rafael Ramírez, former PDVSA head, on the convenience of ExxonMobil to continue operating the asset.
In the next years, refinery capacity utilization was diminished under a new plan oriented to maintain operations only in the most profitable processing units. Moreover, other causes contributed to this reductions, including crude oil and other inputs supply delays.

3. 2012: Intention to sell is announced. In 2012, Rafael Ramírez made public the intention of dissolve the ExxonMobil association in refining, clarifying that any measure would be taken until ICSID decision would be announced. In July 2014, three months before the judgment, many news channels disclose that PDVSA was in search of potential buyers for its Chalmette stake.

4. Chalmette's relevance. While this refining asset was not considered strategic for PDVSA, in 2014 total crude coming from PetroMonagas (former Cerro Negro JV and now operated jointly with Rosneft) was 45-50 tbd. Besides, part of the refinery's output consisted in naphtha and other inputs required for current operations in the Orinoco Oil Belt, since they can be used as diluent for extra heavy oil upgrading process.
In this regard, PBF Energy head (the buying company) said they will hold a supply agreement with Venezuela and that they will expand their provider portfolio given the availability of crudes coming from Mexico and Canada. This means a potential decline in the placement of Venezuelan crudes in the coming years inside the U.S.

5. Where will the money go? According to some analysts, it is possible that the refinery sell-off income will be used to pay the compensation debt owed to ExxonMobil after de ICSID judgment. However, under no circumstances this would be a significant contribution to PDVSA finances, and it is even less significant when compared to the revenue fall registered in the last months.

Chalmette history evidences the opportunities lost to add value in the commercialization of heavy and extra-heavy crude oil, due to its strategic location and technological capabilities. In addition, this refining asset could provide some valuable inputs for the development of the Orinoco Oil Belt. Conversely, the association did not fully profit from all this advantages and, in the voice of parties involved, the relationship between PDVSA and Exxon harmed the performance of the operations in the last years.

In an evolving environment which is more and more competitive for Venezuelan heavy oil placement and where the global energy mix can suffer drastic changes in the medium term, market value of oil products is highly linked to the existence of agreements and other means of positioning in consumer countries. The challenge is related to create the capacity to identify opportunities to create value and not to waste them on raising short term funds.

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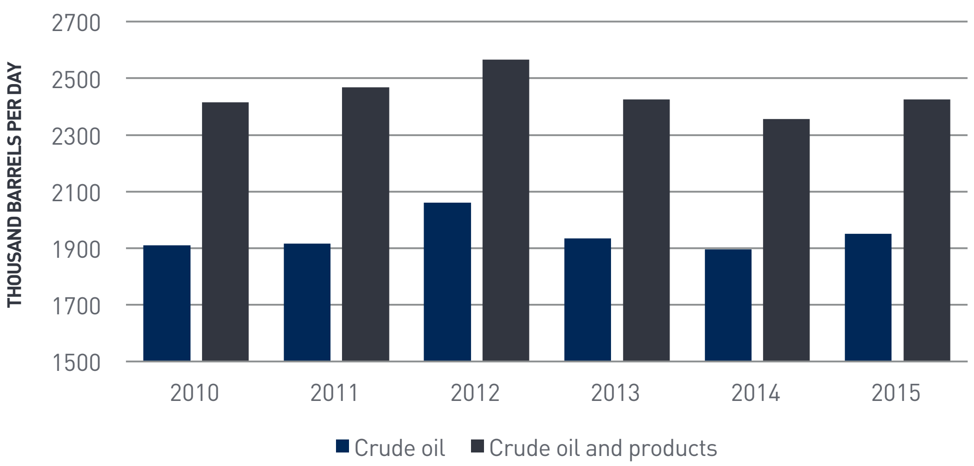
Commercialization

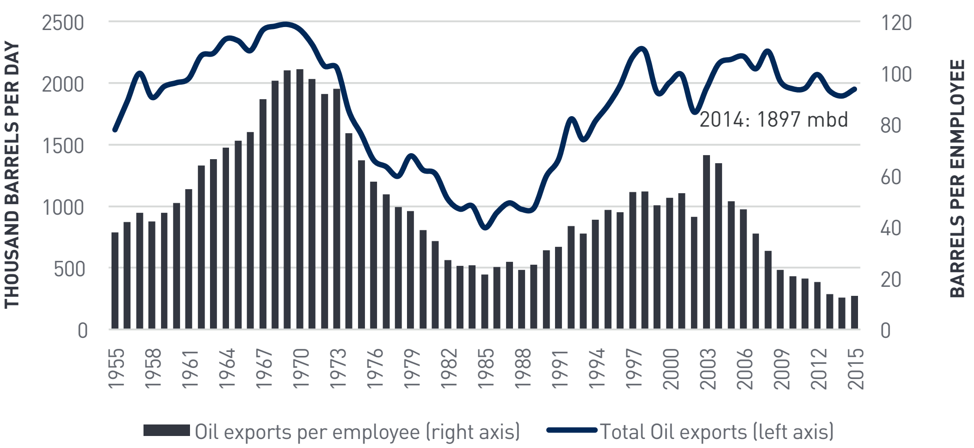
According to PDVSA, Venezuela exported 2,357 tbd of oil and products and 1,987 tbd of crude oil in 2014. Near 38% of all hydrocarbon exports were destined to Asia and 30% to North America. Note that the share of distillates dropped and residual fuels increased in the refined products exports

Figure 29 Crude oil and products exports (2010-2015)

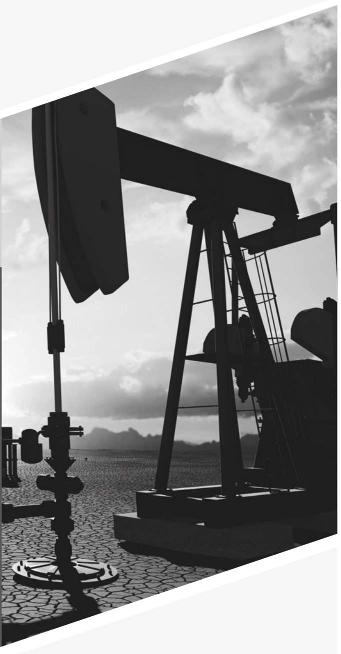


Source: Annual Management Report 2015 (PDVSA, 2016).

Figure 30 Exports volume of PDVSA, total and per employee (1955-2015)

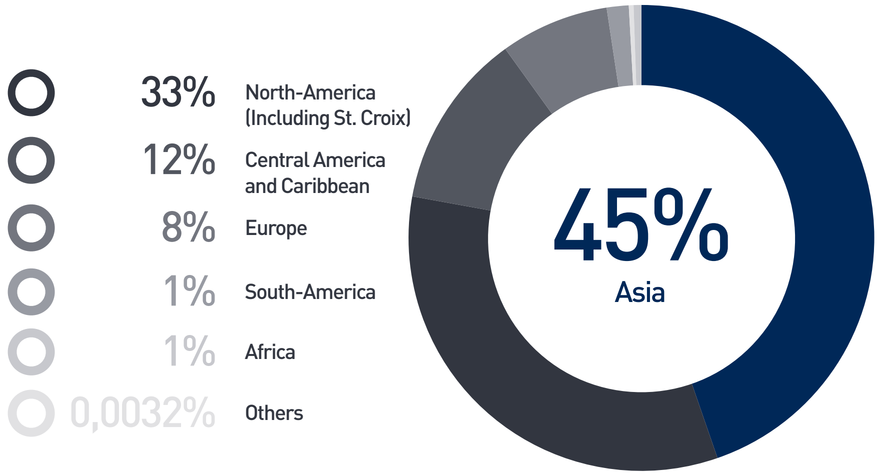


Source: PODE (MENPET, 2012) and Annual Management Report 2015 (PDVSA, 2016).



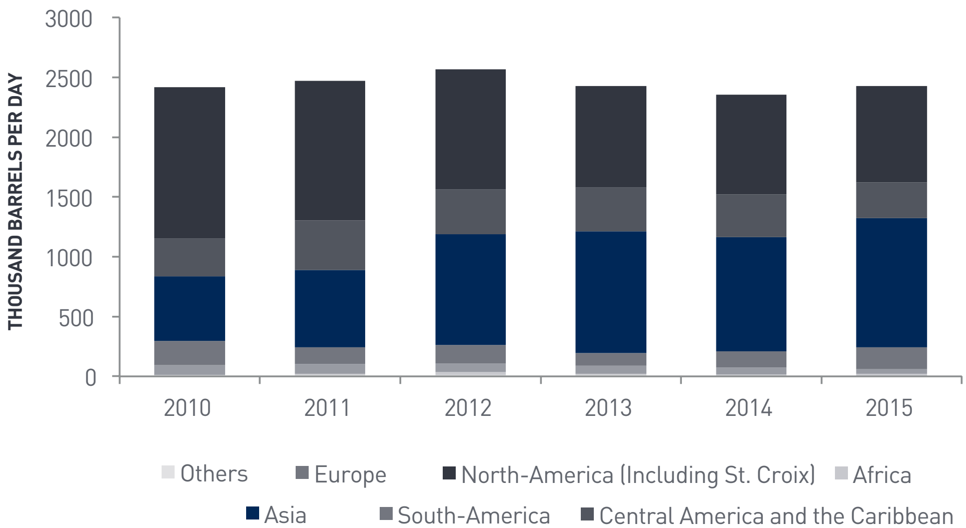
DESTINATION FOR VENEZUELAN EXPORTS

Figure 31 Crude oil and products exports by region, 2015



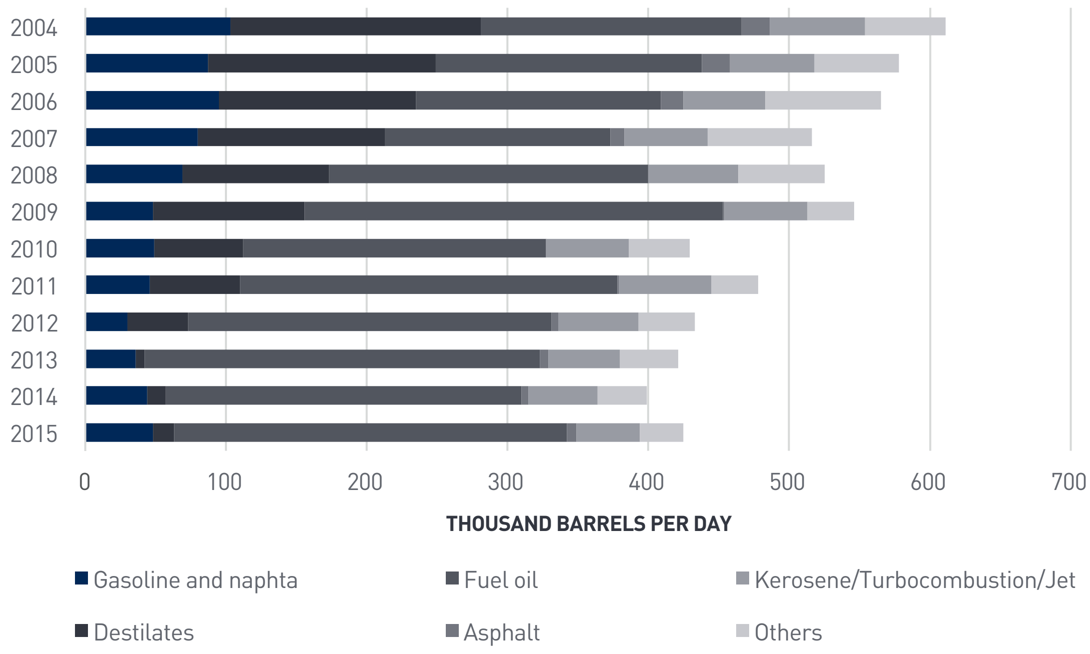
Source: Annual Management Report 2015 (PDVSA, 2016)

Figure 32 Crude oil and products exports by region of destination (2010-2015)



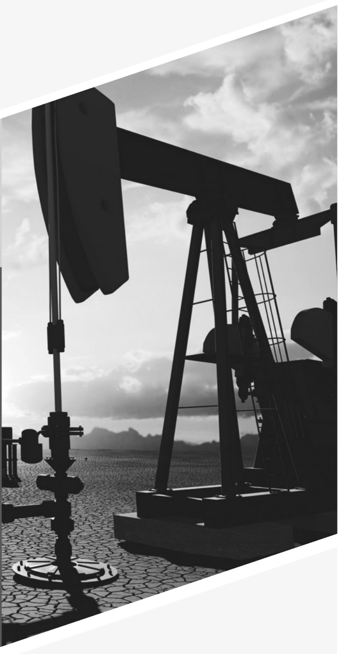
Source: Annual Management Report 2015 (PDVSA, 2016)

Figure 33 Exports classified by product (2004-2015)



Source: Annual Management Report 2015 (PDVSA, 2016).

Fiscal Regime and the Oil Sector



PDVSA's financial results show inconstant performance in recent years. This performance changed due to oil price volatility, operational outcomes, disbursements related to social development programs and, more recently, effects of exchange rate arrangements of reference.

Starting in 2009 until 2012, total income related to crude oil and products sales grew steadily at a compound annual growth rate close to 20%, given the rising price of the Venezuelan basket. This process stopped in 2013-2014, when total sales diminished 8% per year and it deepened in 2015, as sales fell 40%. Nonetheless, financial income compensated this decline as a result of currency exchange gains following the implementation of the Sistema Complementario de Administración de Divisas (SICAD), in March 2013. This scheme authorized PDVSA to sell foreign currency to a higher rate and generate additional earnings in local currency in 2014 and 2015 too, when even more favorable exchange rates allowed to generate financial income.

Table 5 Resume of PDVSA consolidated (restructured) financial statements (2013-2014, USD million)

	2013	2014	2015
INCOME	**120.035**	**121.895**	**72.169**
Crude Oil sells, subproducts and other products	110.719	101.552	55.339
Financial income	9.316	20.343	16.830
COSTS AND EXPENSES	**95.104**	**100.257**	**61.511**
Oil and subproducts purchases	36.754	37.266	22.965
Operational, sale, administrative and general expenses	23.733	27.400	16.282
Exploration costs	140	76	50
Depreciation, depletion and amortization	8.096	8.038	8.995
Royalty, extraction taxes and other type of taxes	19.262	13.466	6.294
Financial expenses	2.880	4.065	2.393
Other expenses/net income	4.239	9.946	3.986
INCOME/NET LOSS BEFORE INCOME TAXES AND SOCIAL CONTRIBUTIONS	**24.931**	**21.638**	**10.658**
CONTRIBUTIONS FOR SOCIAL DEVELOPMENT	**13.023**	**5.321**	**9.189**
INCOME/NET LOSS BEFORE INCOME TAXES	**11.908**	**16.317**	**1.469**
INCOME TAX	7.186	5.106	-3.717
INCOME/NET LOSS OF CONTINUOUS OPERATION	**4.722**	**11.211**	**5.186**
Income/Net loss of discontinued operations	11.113	-2.137	2.159
NET INCOME	**15.835**	**9.074**	**7.345**

Source: Annual Management Report 2015 (PDVSA, 2016).

Finance income growth, decreasing social net contributions and diminishing total costs and expenses, explains the increase on net results of PDVSA in 2013. Furthermore, PDVSA sold to the Central Bank its 40% participation into the National Auriferous Company in a 135.6 VEF billion transaction. The payment produced 58 VEF billion income due to a compensation via accounts payable to the Oficina Nacional de Presupuesto (ONAPRE), the budget office, at SICAD exchange rate.

Net income in national currency converted to USD at the official exchange rate hiked three-fold, from the last four years average terms to 15.84 USD billion in 2013. This result could not be sustained in 2014 due the oil price slump, which decreased total income in 5.89 USD billion, and to the growth in total costs and expenses of more than 10.5 USD billion. Despite extraction and other taxes and social development expenses diminished, net income contracted 43% in 2014 as compared to last year.

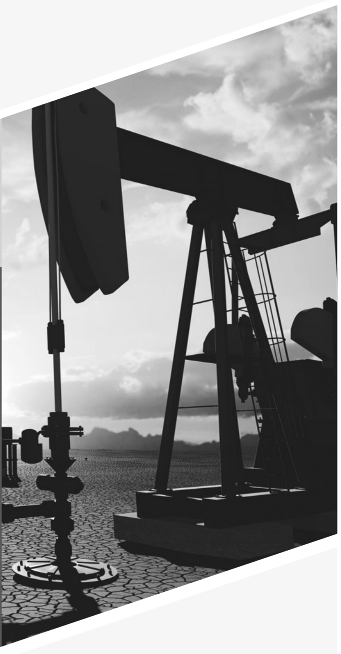
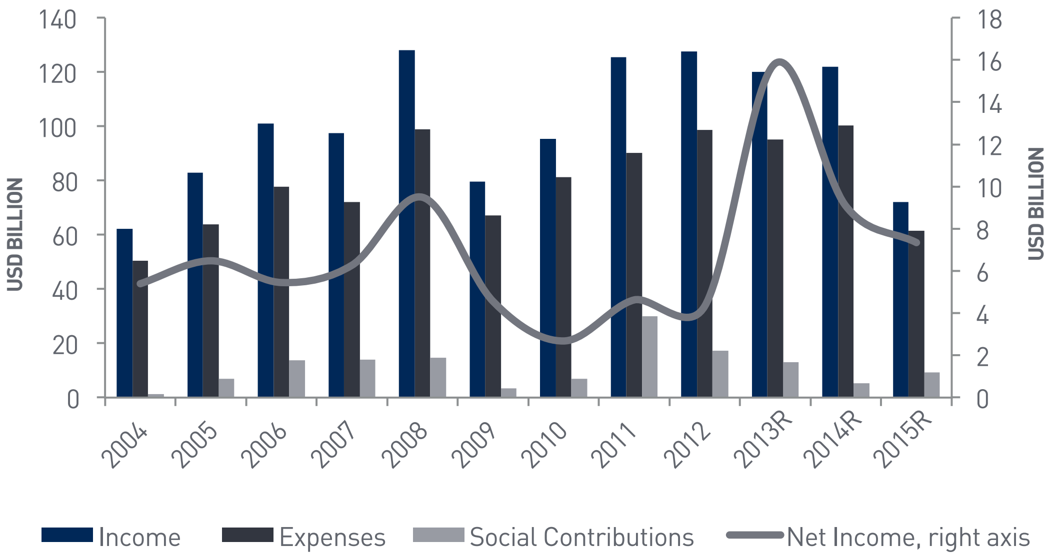


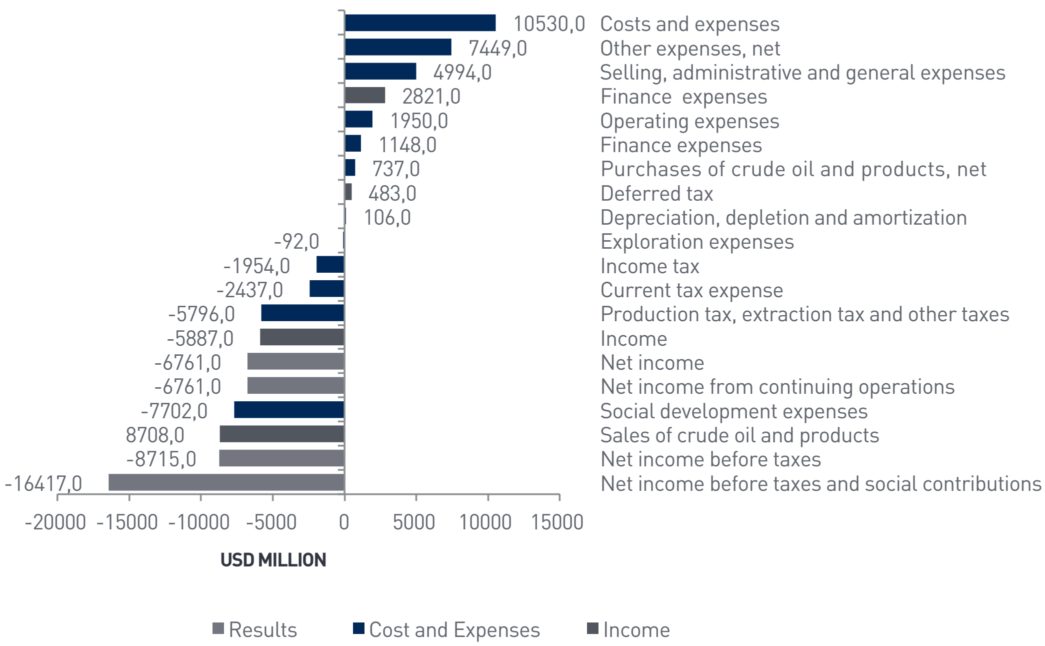
Figure 34 Annual PDVSA results (2004-2015)



Source: Annual Management Report (PDVSA, various years).

Sustained increase in total costs and expenses since 2009 harmed PDVSA's net results. Furthermore, recent income dropped despite important social budget cuts and growing financial income, mainly due to foreign currency exchange gains. Diminishing social development expenses is related to the recent reform to the Windfall Oil Price Law. This reform increased the threshold by which an extraordinary 20% on income contribution should be submitted, reducing substantially transfers to the Fondo de Desarollo Nacional (FONDEN), an off-budget expenditure vehicle for the government.

Figure 35 Main variations in income statements between 2013 and 2014



Source: Annual Management Report 2014 (PDVSA, 2015).

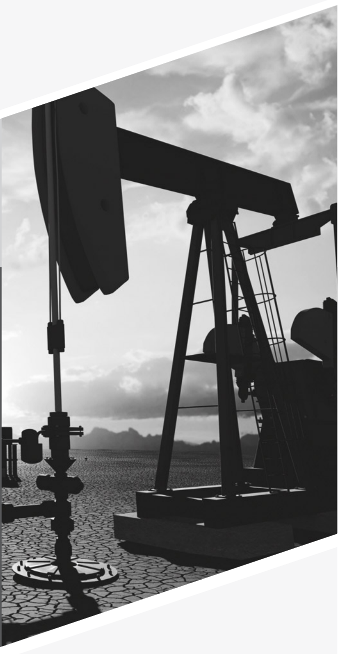
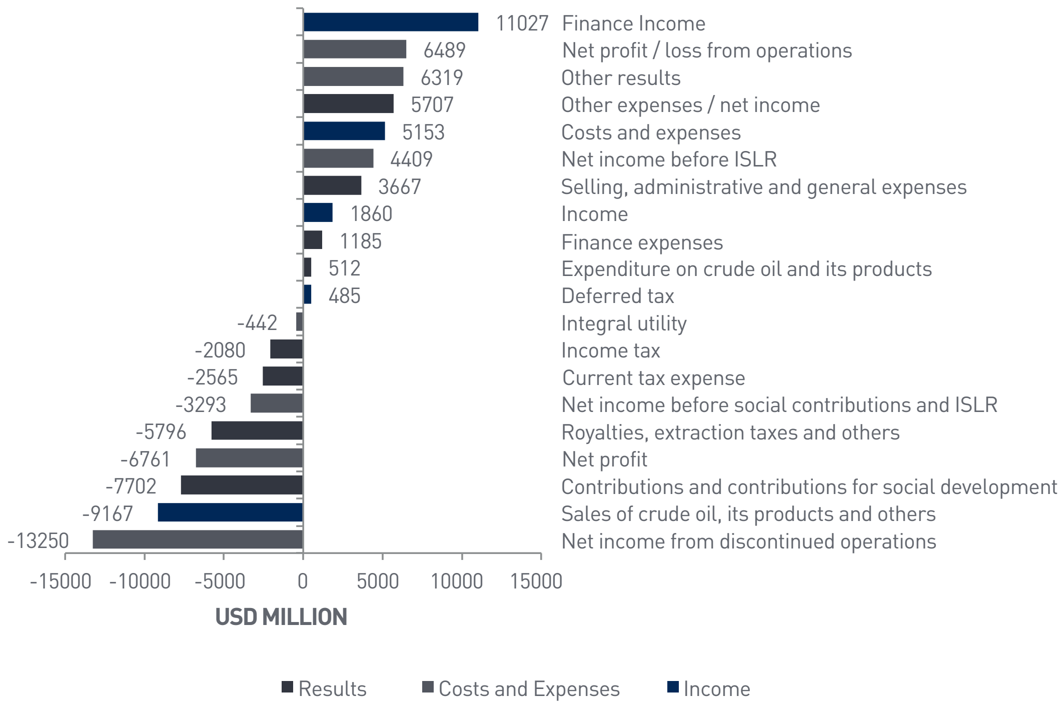


Figure 36 Main variations in income statements between 2013 and 2014 (Restructured financial statements)



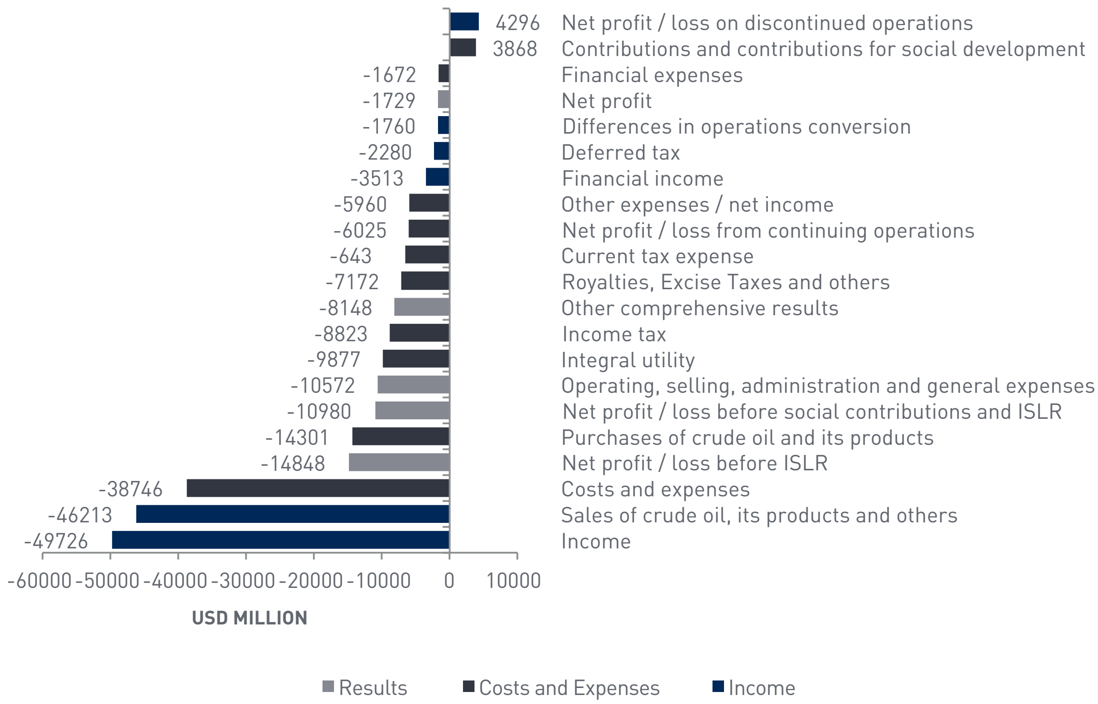
Source: Annual Management Report 2015 (PDVSA, 2016).

From the 21 main variations in 2013-2014, the only expenses that exhibited relevant decrease were production and extraction taxes and social development expenses. These figures were published in 2014 and do not include the firm's recent restructuring process.

In the pre-restructuring scheme, costs and expenses showed important increases. "Other expenses" accounts a rise of over 7.440 USD million yoy. This increase –not seen historically– is due to the cancelation of "work in progress", legal contributions, irrecoverable tax credits, provisions for litigation and fall in the assets value (mainly refining assets), according to PDVSA.

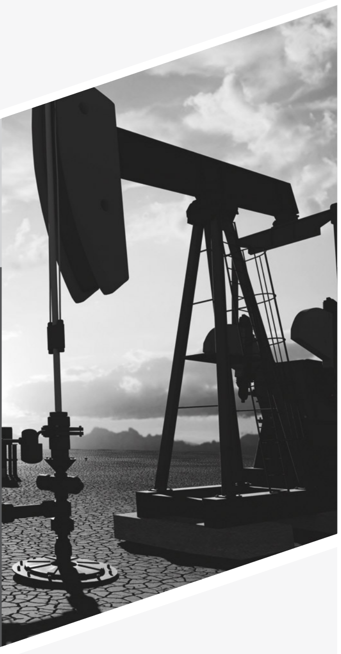
The restructuring process, which implied the withdrawal of subsidiaries, modified these results in the most recent report from PDVSA. In the period 2013-2015, the financial statements are recomposed towards a reduction in expenses and an increase in income. The increase is explained by financial income related to transactions with the Central Bank, according to the company.

Figure 37 Items with the largest changes between 2014 and 2015 (Restructured financial statements)



Source: Annual Management Report 2015 (PDVSA, 2016).

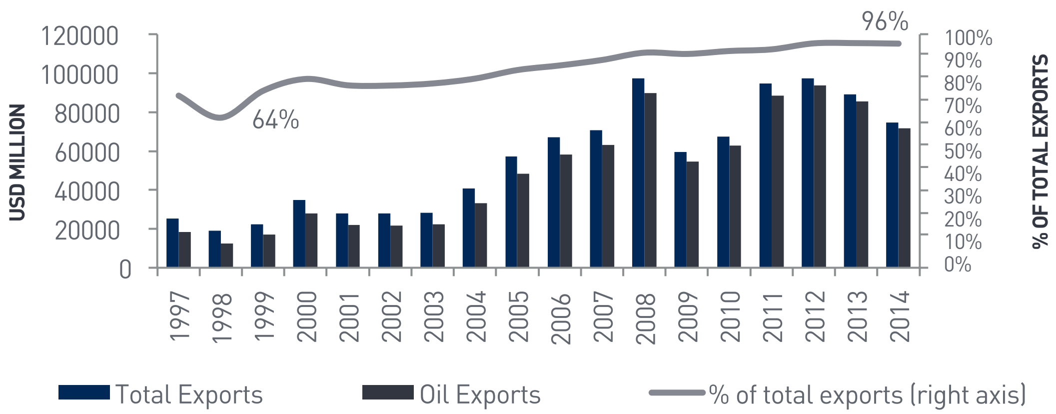
Between 2014 and 2015 most of the items of income varied negatively, with the exception of the profit from discontinued operations and contributions to social development. Revenues were the most adversely affected, with a slump explained by the sales of crude and products. Likewise, costs and expenses also reduction as a result of the fall of all its components.



OIL INCOME AND EXPENDITURES OF THE REPUBLIC

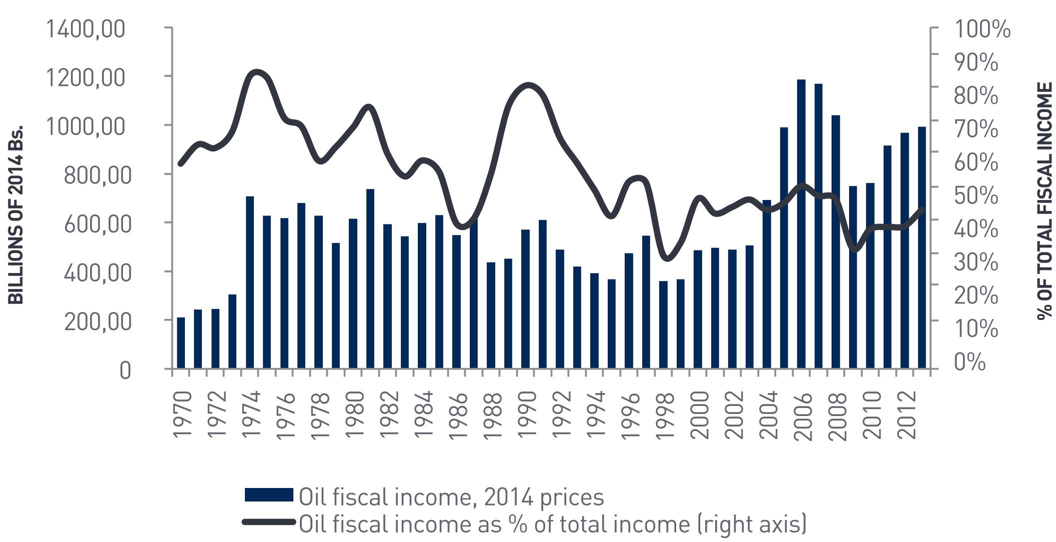
As of third quarter 2014, Venezuelan oil exports reached 94% of total exports, according to official figures. Petroleum exports dropped 16% that year, following an 8% dive during 2013. Overall decrease amounts 23% as compared to 2012, a deep shock on fiscal accounts as 42% of total income arises from oil sector contributions. To date, there have been no official releases of exports and fiscal accounts figures for 2015.

Figure 38 Venezuelan oil and total exports (1997-2014)

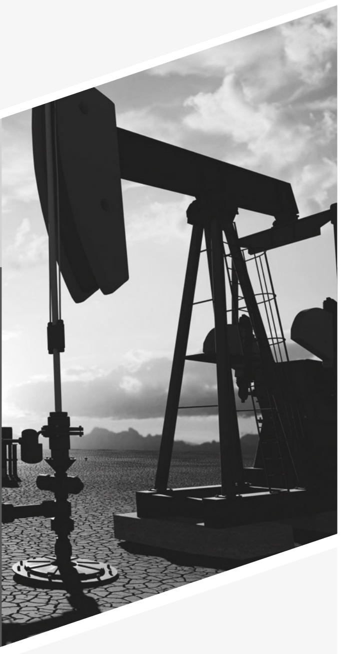


Source: Información Estadística (BCV, various years).

Figure 39 Fiscal Oil Income (1970-2012)



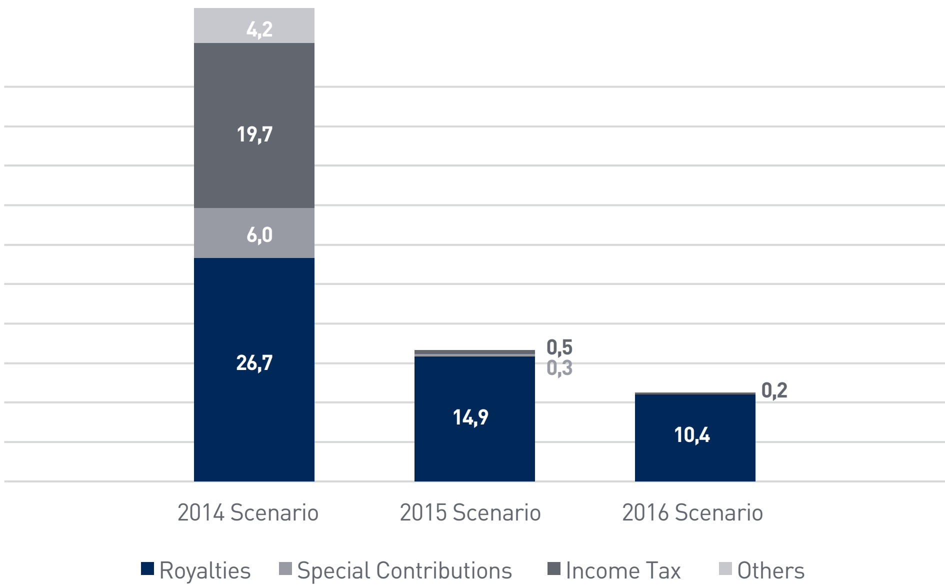
Source: Gobierno Central Presupuestario (MEFBP, 2013) and CIEA.



FISCAL REGIME

At CIEA, we have simulated fiscal contributions from oil companies operating in Venezuela considering the existing fiscal framework. Our government take model allows to account on the transference made to fiscal authorities given different oil price scenarios. In 2014, with an average price of 88 USD per barrel and estimated operational and capital expenditures of 28.73 USD, the government receives 56 USD per barrel. In 2015 tax authorities receives 15.6 USD per barrel produced. Finally, in 2016, government take amounts 10.6 USD per barrel. Special contributions were reduced from almost 24 USD per barrel to zero due to the lower prices during 2015 which, combined with a lower income tax, explains most of government take drop[3].

Figure 40 Government Take Scenarios (2014-2016, USD per barrel)



Source: CIEA.

[3]2014 Scenario: based on an average Venezuelan basket price of 88 USD per barrel, an expected average price of 60 USD per barrel for government budget (Ley de Presupuesto) and for a project in which CAPEX and OPEX accounts for 28.73 USD per barrel. Government take amounts 56.59 USD per barrel.
2015 Scenario: based on an average Venezuelan basket price of 45 USD per barrel, an expected average price of 60 USD per barrel for government budget (Ley de Presupuesto) and for a project in which CAPEX and OPEX accounts for 28.73 USD per barrel. Government take amounts 15.64 USD per barrel.
2016 Scenario: based on an average Venezuelan basket price of 31 USD per barrel, an expected average price of 40 USD per barrel for government budget (Ley de Presupuesto).

GOVERNMENT -TAKE BY TYPE

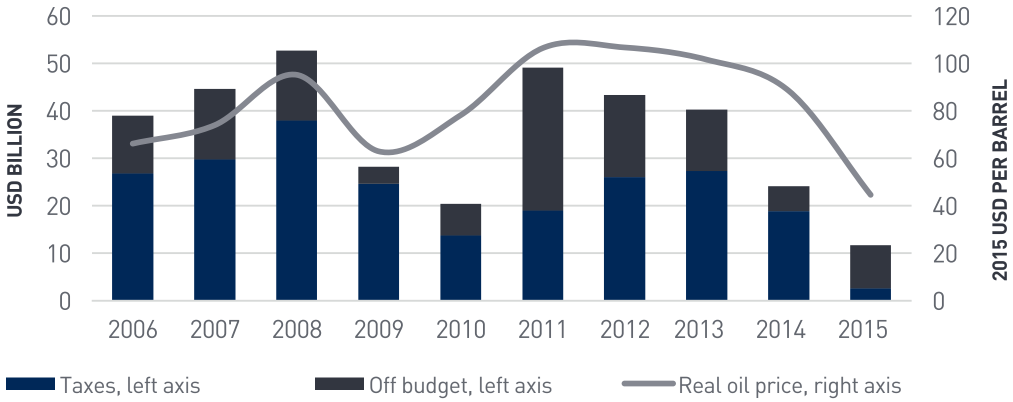
Hydrocarbon sector makes contributions to fiscal accounts through two mechanisms: budget and off-budget. Fiscal contributions dropped 51% between 2014 and 2015, representing close to a half of government revenues.

Budget contributions in 2014 were composed by 11.9 USD billion in cash royalties (62% of the budget and 48% of total contributions) and 5.8 USD billion corresponding to Tax Income (30% and 24% of the budget and total, respectively). During 2014, taxes represented 78% of PDVSA's contributions and fell 30% as compared with previous year.

In 2015 total budget contributions plummeted 86%. Income tax represented -3.7 USD billion, due to deferred tax discounts and a negative effective rate related to inflation and currency exchange rate adjustments. Cash royalties dropped 53%, reaching 5.6 USD billion (49% of total contributions) and other taxes added up 669 USD million.

Even when government take is used as a reference measure of state participation in oil business, off-budget transferences remain as an important contribution channel to the government in Venezuela. Off-budget contributions amounted 5.3 USD billion in 2014, 22% of total taxes. Parafiscal contributions dropped by 59% with respect to 2013. Nonetheless, in 2015 total off-budget grew by 73% and amounted 9.1 USD billion.

Figure 41 Fiscal Contributions and real oil price (2006-2015)



Source: Annual Management Report (PDVSA, 2014), Cesta Venezolana (MENPET, various years) and FRED (St. Louis FED, 2016).

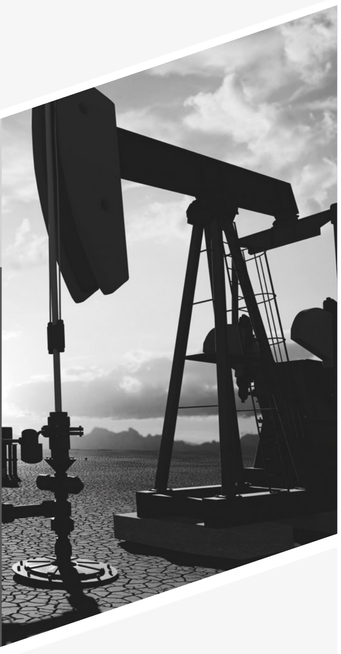
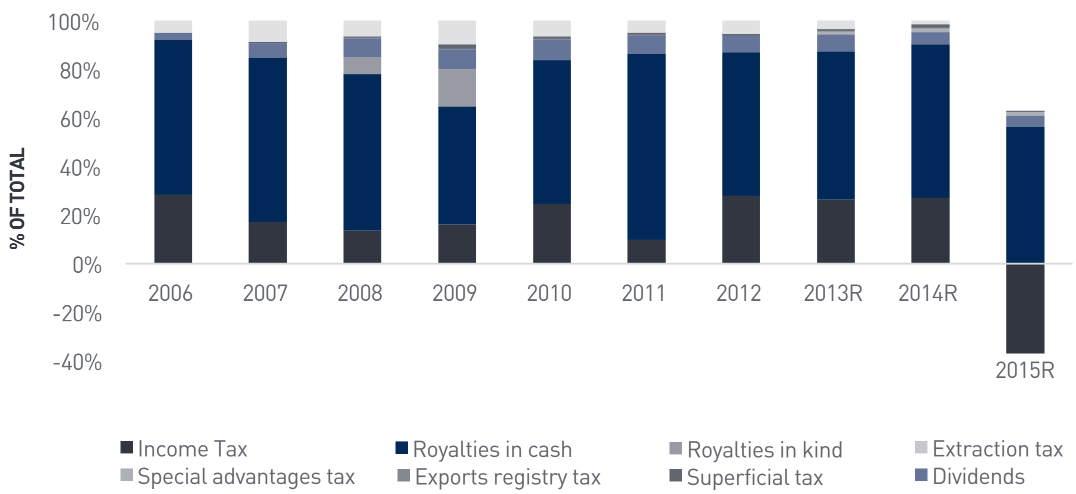
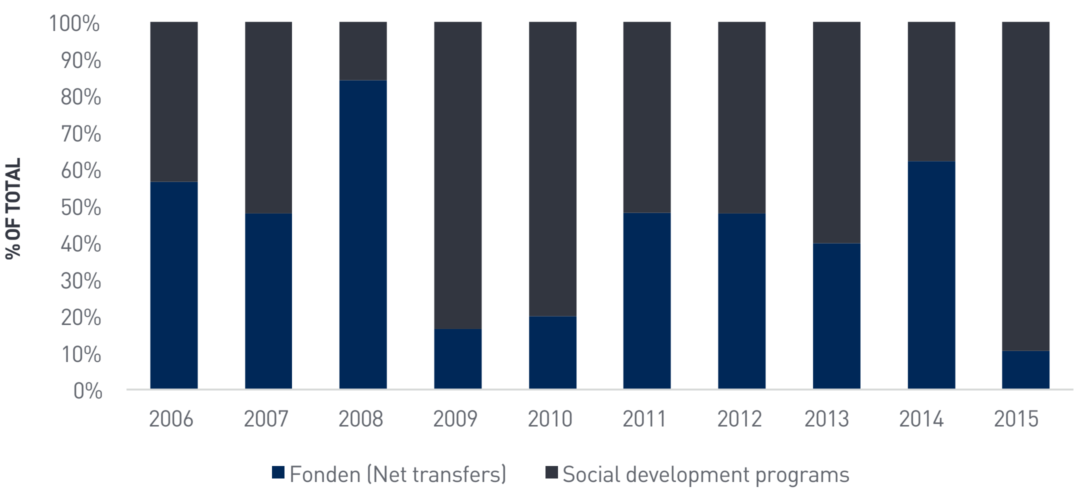


Figure 42 Fiscal contributions by type, (2006-2015)



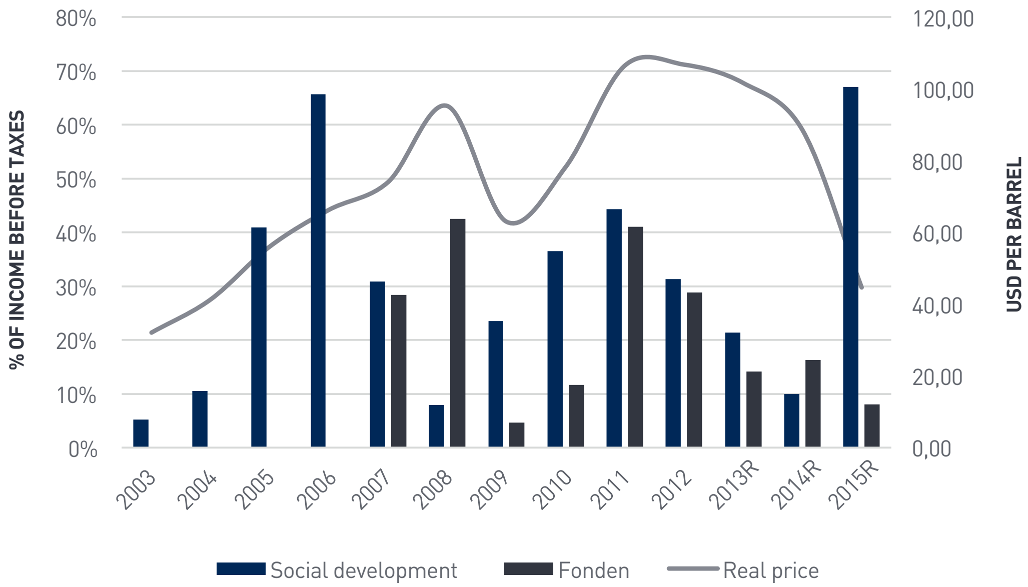
Source: Annual Management Report (PDVSA, 2014).1

Figure 43 Off-Budget Contributions (2006-2015)

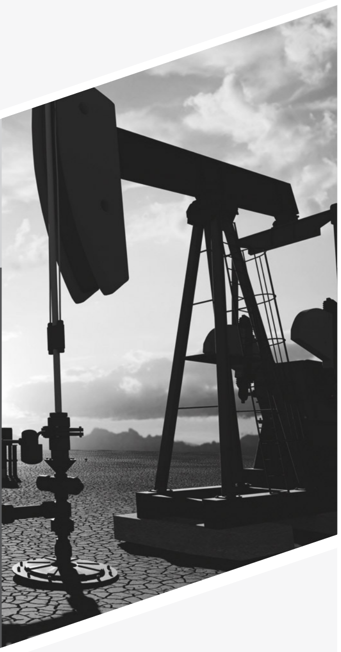


Source: Annual Management Report 2015 (PDVSA, 2016)

Figure 44 Social Development Expenses as percentage of income before taxes (2003-2015)



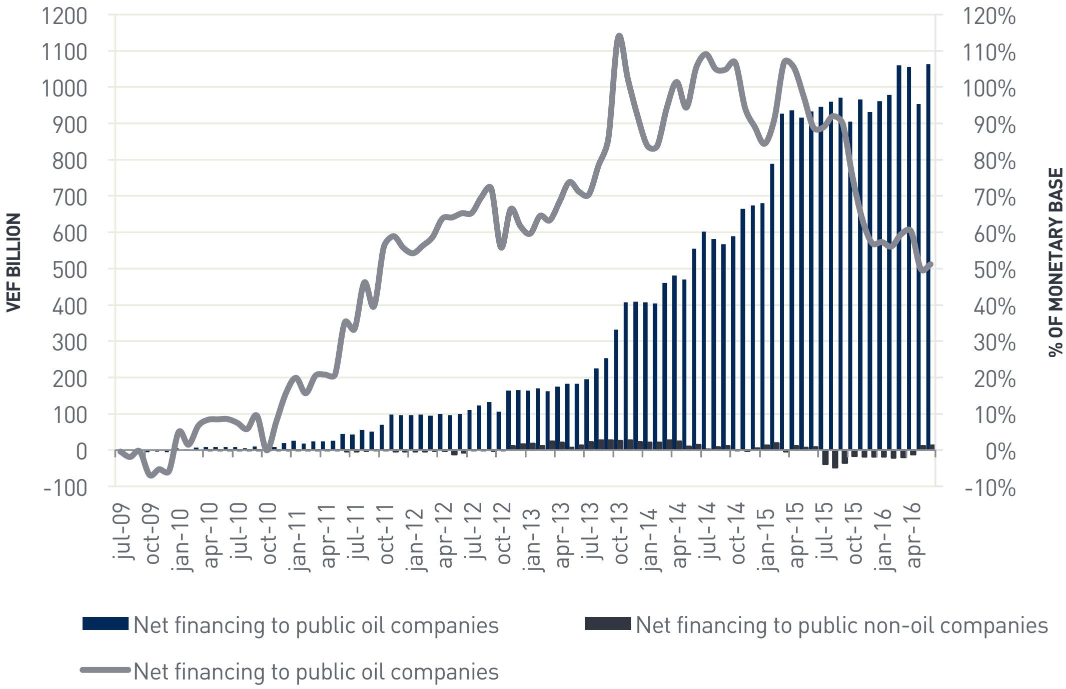
Source: Consolidated Financial Statements (PDVSA, various years)



MONETARY FINANCING TO PDVSA

The reform made to the law of the Venezuelan Central Bank, which authorized the bank to finance public enterprises, served to fund PDVSA in bolivars. Entering in effect in May 2010, the reform allows the acquisition of PDVSA's debt by the Central Bank under the discretion of the Executive branch and the lending conditions of the bank's board.

Figure 45 Net Financing to Public Oil and Non-oil Companies by the Central Bank



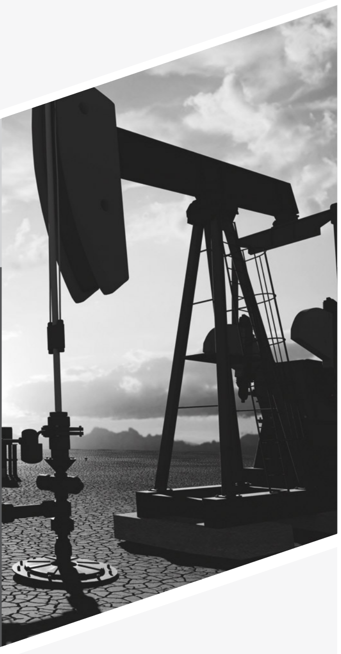
Source: Información Estadística (BCV, 2016).

Public oil companies financing (PDVSA and subsidiaries) closed 2014 with a balance over 674 billion of VEF and reached more than 965 billion of VEFin November 2015. This implies a growth of 142% in 2014 and 74% until November 2015. In terms of the monetary base, the magnitude of the amount grew more than 100% during two months of 2013, five months of 2014 and two months of 2015.

PDVSA reports several indebtedness operations with the Central Bank since 2010. At the end of 2014, PDVSA had sold over 130 billion of VEF in promissory notes to the monetary authority, 84% of the accounts payable to related parties. Only this year, the oil company issued more than 87 billion of VEF in these notes, which pays a fixed 0.51% annual interest rate and mature between 2016 and 2022.

Promissory notes operations have been complemented with fixed income allocations to the Central Bank. In 2010, PDVSA awarded the bank 1.48 billion of VEF in Petrobonos, later exchanged by notes for over 33.437 billion of VEF. Other instruments, such as investment certificates, have been allocated and later exchanged with premium to the Central Bank.
In the period 2010-2013, PDVSA awarded bonds denominated in dollars to the Central Bank, including PDVSA 2017, 2021, 2026 and 2035. Most of the operations were made with a premium for the company. Besides, diverse social development funds were constituted in the same period.

Monetary financing to PDVSA reached a peak in nominal terms by March 2016, after exceeding 1.6 VEF trillion, which has been reduced in recent months. Nonetheless, in relative terms, its level started to descend a year before, when it was 105% of monetary base.



VENEZUELA AND OPEC: INVESTMENT FUNDS AND INTERNATIONAL RESERVES

The oil price super-cycle, which begins with the hike in crude oil since 2003, has generated substantial income to OPEC countries through their NOCs fiscal contributions. This permitted the accumulation of assets into savings or investment funds by the States as institutional investors.

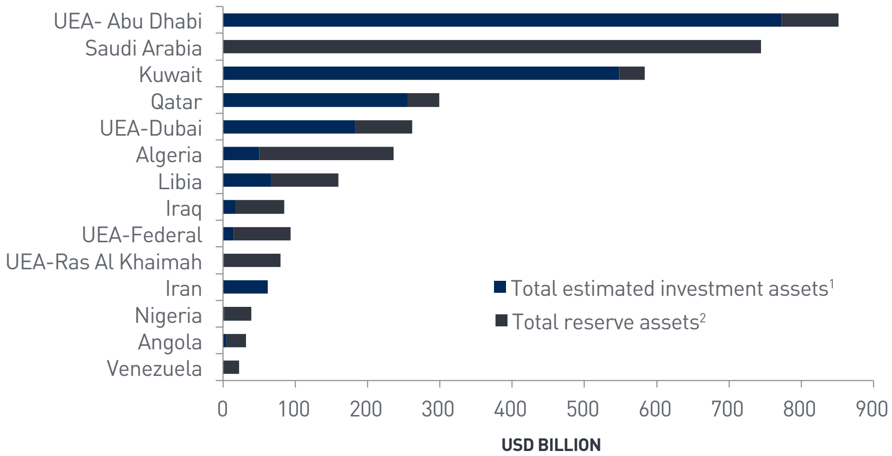
A sovereign wealth fund is a State property fund which earmarks the surplus income from fiscal and external accounts for investment in financial assets. According to the Sovereign Wealth Institute, since 2005 at least thirty new investment funds have been created. Sovereign assets represent 3% of total settled in worldwide financial markets, growing 59% from 2008 to 2012. Five of the top-ten wealth funds in the world –as measured by assets size– received their income from oil and its production of derivatives, with 59% of all the funds coming from the oil and gas industry itself.

Investment assets accumulation has allowed to big oil exporter countries, particularly those from the Cooperation Council for the Arab States of the Gulf, to reduce the impact of recent oil price slump. The availability of abundant liquid assets has permitted to balance their domestic economies by purchasing imports of financing fiscal deficits. Even when some countries are thinking to accomplish structural changes in the middle to long term, sovereign funds can boost the initial transformation in the short term.

OPEC countries could amass more than 2 USD trillion in total investment assets, more than international reserve assets which were 1 trillion and 580 USD billion in June 2015.
This calculation accounts for Saudi Arabia assets as international reserves, even when many of them are earmarked for investments which would make the number bigger.

The assets accumulation has allowed big oil producers, mostly Saudi Arabia and other countries from the Cooperation Council for the Arab States of the Gulf, to reduce the impact of recent price fall. The availability of abundant foreign currency and other portfolio assets have been employed to minimize the impact of macroeconomic adjustments related to oil income drop.

Figure 46 Investment and International Reserve Assets, selected OPEC Countries



Source: Fund Rankings (SWFI, 2016), DataBank (World Bank, 2016), Información Estadística (BCV, 2016).

[1] June of 2015.
[2] End of 2013 for Iran and end of 2014 for the others.
Note: Saudi Arabia does not publish figures for its investment assets

This is not the case for Venezuela, whose main fund named Fondo de Estabilización Macroeconómica (FEM) closed 2015 with a meager balance of 3 USD million (which is not visible in Figure 38). Established in 1998 as an investment and macroeconomic stability fund, the FEM has suffered several modifications to its accumulation rules. Even when the fund collected once over 6 USD billion, the current size does not allow the country to balance its fiscal and external accounts in the face of a severe external liquidity crunch and internal imbalances.

Even when taking into account only the international reserves, Venezuelan sovereign liquid assets position remains as the weakest of the OPEC. International reserves closed 2014 and 2015 with 22 and 12 USD billion, respectively, well below the average of its counter-parts, which roses 112 USD billion in 2014 and 109 USD billion in 2015.

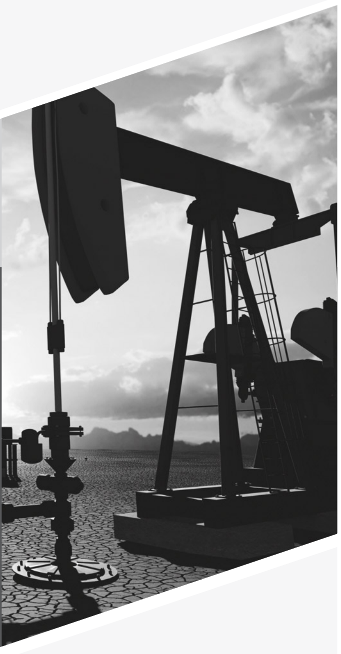
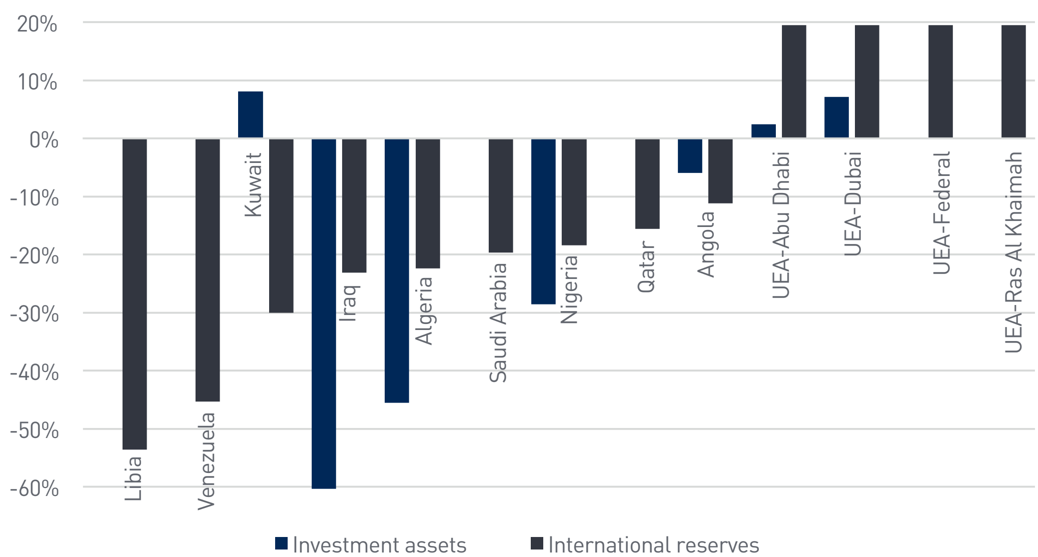


Figure 47 Reserve and investment assets annual percent change, selected OPEC countries (2015-2016)



Source: Fund Rankings (SWFI, 2016), DataBank (World Bank, 2016), Information from Central Bank 1 (BCV, 2016)[1].

[1] Iran has been excluded as its investment assets did not change and there is no available data on its foreign reserves in 2016

Libya, Kuwait and Venezuela have the heaviest losses in terms of international reserves in 2015, when the oil prices plummeted. The most affected investment funds were those of Iraq, Saudi Arabia and Nigeria. The UAE have shown endurance to the price shock by even closing with higher international reserves in the same year.

BOX /4

THE LONG AND WINDING ROAD OF OIL RENTS

- BY DIEGO GUERRERO -

Beginning in the 20th century, rents from oil exploitation have been in the center of the public debate in Venezuela. From the outset of the country's oil industry history, several groups pressed in order to enhance the share of the State in the sector's income. The underlying idea consisted in making use of oil fiscal revenues to boost industrialization across the economy. An analogous conception was the "oil sowing", aimed to allocate oil rents to encourage agricultural investments. During the last 20 years, a local or endogenous development discourse has prevailed as complemented with social distribution of oil wealth.

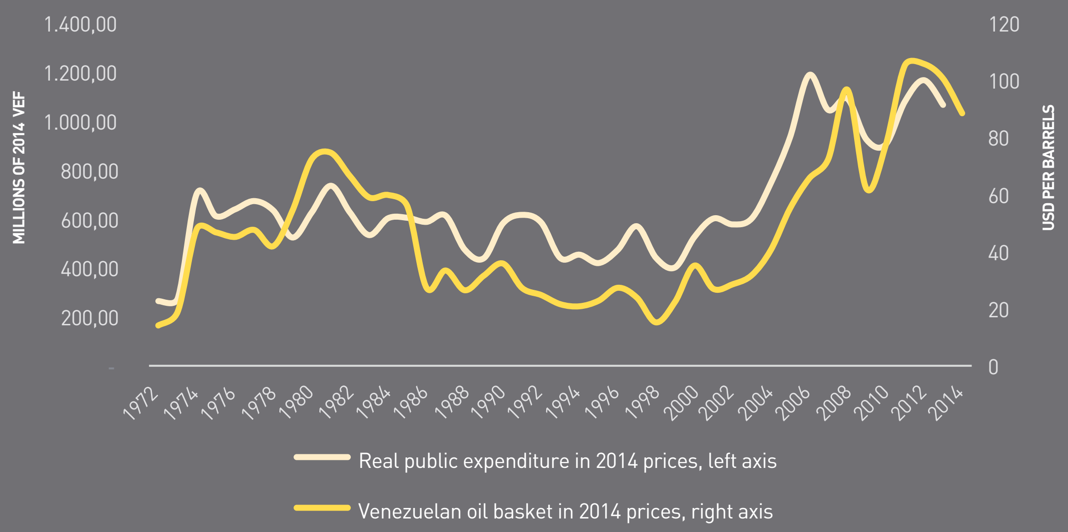
In 2017 Venezuela will commemorate a hundred years after the first oil export and the rent issue is still under discussion into the political and academic arena. Meanwhile, the economy and the population suffer the consequences of little progress in isolating the economy from the oil market swings.

The design of a strategy which takes advantage from the rent comes from two essential elements. First of all, the domestic effects of the resource price volatility must be mitigated. In that sense, the way that rents drive, distortion or restrict political decisions must be clarified. Secondly, economic dynamics of petroleum exporters should be examined carefully. This is especially relevant when it comes to the productivity and the incentives caused by rent distribution. Political dynamics are key on these matters and, henceforth, we will examine their implications.

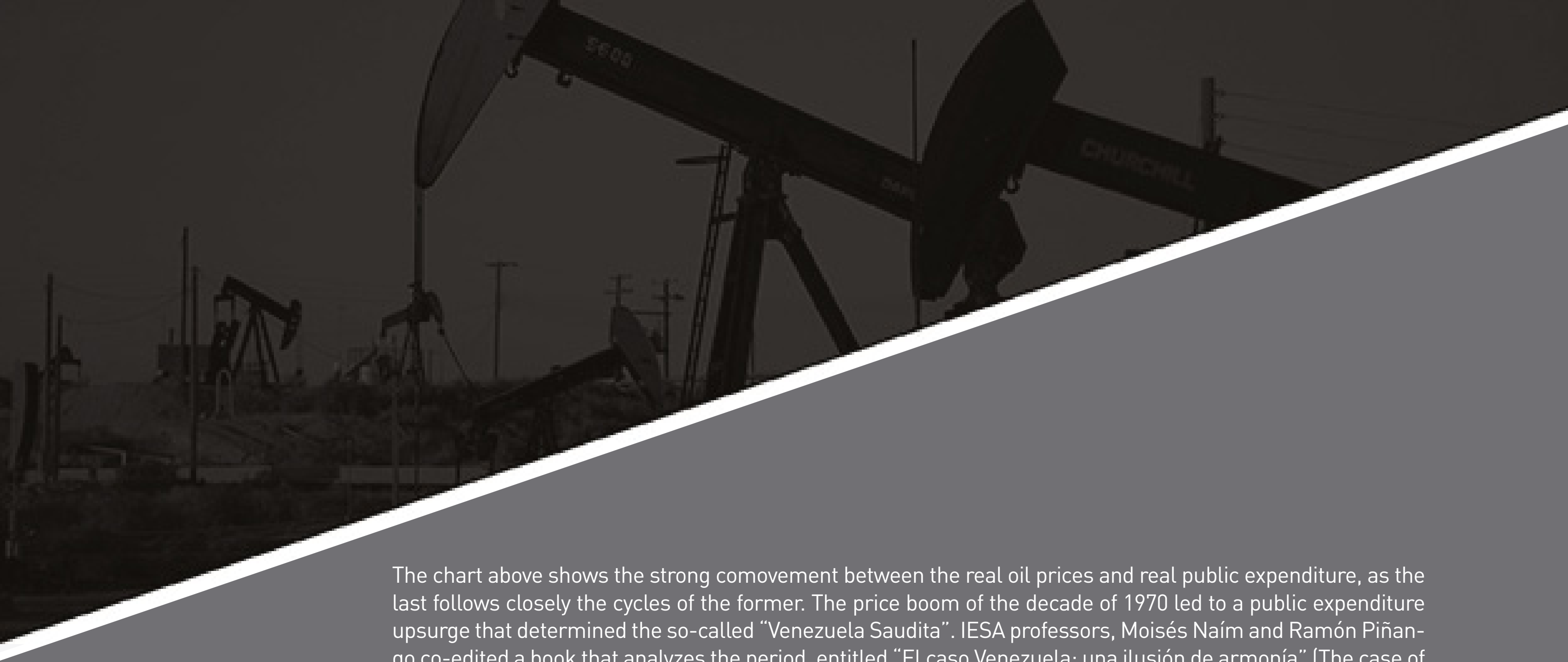
Rents and the political cycle

The State's share in oil income generates substantial revenues to fiscal accounts. By definition, fiscal revenues are distributed through public spending and shape political cycles. High revenues allow more expenditure. This offers political gains to governments, whose approval and popularity rates rise in boom periods.

Real public expenditure and real oil price (1972-2014)



Sources: Cesta Venezolana (MENPET, 2016), Memoria y Cuenta (MEFBP, various years), Información Estadística (BCV, various years).



The chart above shows the strong comovement between the real oil prices and real public expenditure, as the last follows closely the cycles of the former. The price boom of the decade of 1970 led to a public expenditure upsurge that determined the so-called "Venezuela Saudita". IESA professors, Moisés Naím and Ramón Piñango co-edited a book that analyzes the period, entitled "El caso Venezuela: una ilusión de armonía" (The case of Venezuela: an illusion of harmony). The headline is revealing by itself, as income windfall concealed structural deficiencies and fostered modernization without regard to internal conflict resolution.

The oil price drop in the 1980 decade caused more than economic changes. Public sector reforms aimed to decentralize power and reduce presidential discretionarily, as well as diversify tax mechanisms while increasing the government's tax revenue. Political crisis and conflicts in political parties were deeply stressed, while electoral abstention and generalized discontent deepened. In the midst of political unrest during 2003 structural reforms took place. Oil price hiked and once again provided incentives for rent appropriation and distribution. Social "Missions" policies were born that year. But the high point in this new cycle is clear with the introduction of a set of new laws which allowed to manage oil income in parallel to public budget.

It is a mistake to think Venezuelan political history and ignore oil income dynamics and the incentives it creates in ruling classes to administer political power through rent-seeking behavior. At the same time, the public sector behavior determinants the circumstances for economic growth. For that reason, political dynamics has been closely related to oil price movements: the initial boom and the current bust.

Although Venezuela got through a painful break in the price cycle, the lesson was insufficient. Oil price hike provoked an upwarding political cycle in the last decade. Leaders' temptation to benefit from rents to gain popularity were strong, even when the system's exhaustion and income depletion was likely. Discretion in oil rent management led to client state practices, rent-seeking behavior and rent capture deviated resources from the production and provision of public goods and services. Hence, the population became vulnerable.

Rents and economic performance

A reform to the Venezuelan Central Bank's law and the creation of the Fondo de Desarrollo Endógeno (Fonden) gave the central government power to dispose oil rents through this fund and PDVSA, evading constitutional responsibilities with municipalities and states. The reform also reduced the National Assembly's capacity to control public expenditure, given its management regardless of budget. With no checks and balances, audit and evaluation of social programs was nonexistent. Finally, these instruments served to finance consumption and not to improve living conditions.

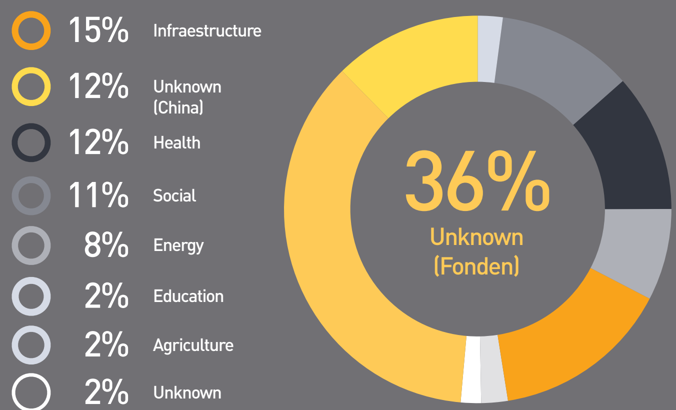
Until this date, Venezuela failed to manage appropriately its resources. Industrialization failed to happen and the efforts to diversify dwindled. This is clear when non-oil related exports are shown. Current industrial base is in no conditions to produce competitive goods and services which generate value for export, with few exceptions.

Neither local development nor poverty goals were achieved. During the last twenty years, expenditure was treated as social investment. Following that model, significant amounts were disbursed into social development programs known as "misiones" through PDVSA and Fonden. These programs were supported on the basis of the aforementioned legislation regarding the extra-budget management of rents.

Discretion allowed to manage non-transparent budget lines. As far as we know, subsidies, loans and investments handled through Fonden and Bandes (Chinese Fund) could have been executed in other social

expenditure categories. But it is unclear how they were allocated and the status of their related projects. As a result, over 40% of social expenditures disbursed through extra-budget mechanisms were allocated in provisions whose returns are not possible to estimate. Meanwhile, flagship programs in education and health, such as "Barrio Adentro" and educational programs do not account more than 15% of total expenses. On the other hand, the big housing program "Gran Misión Vivienda Venezuela" plus other infrastructure expenditures only sum up 15% and pension and social assistance related programs only 11%.

PDVSA social expenditure allocation between 2001 and 2014



Source: Annual Management Report (PDVSA, 2015).

These figures are relevant due to the extent of disbursements which officially rose 200 USD billion between 2001 and 2014. Furthermore, the real invested amounts are unknown due to large differences between PDVSA Management Report and its Consolidated Financial Statements.

Nowadays, two consequences arise from this rent allocation scheme. First, rent distribution over public and private enterprises in sectors like agriculture, industry and energy. In addition to large inefficiencies in the public sector, price and exchange controls combined with high inflation and real exchange rate appreciation reduced dynamism to the private sector. Second, public expenditure growth and rent distribution did not promote human capital growth and productivity gains in the economy. Oil income was devoted to finance a boom in import consumption and alleviated poverty temporarily through income transfers and palliative programs. Nonetheless, it was not possible to promote structural changes in order to overcome poverty in the long term. In sum, due to the lack of fundamental and enduring changes, poverty returned after rent diminishes. In light of productivity losses, workers cannot improve their real income in order to face subsidies cuts in low rents periods.

The underpinning lies on the fundamental idea that oil is only valuable in fiscal terms. Venezuela has not benefited from natural resources abundance to develop more complex goods and services. During the boom of 1970, the goal of reaching productivity gains was not accomplished. The last decades have not been that different.

The Center for International Development, at Harvard Kennedy School of Government, compiled evidence on economic complexity and growth. By analyzing productive knowledge, the CID states that development is not only explained by total production growth, but also by increments in complexity and diversity of production. Commodities like oil and agricultural goods are the less complex.

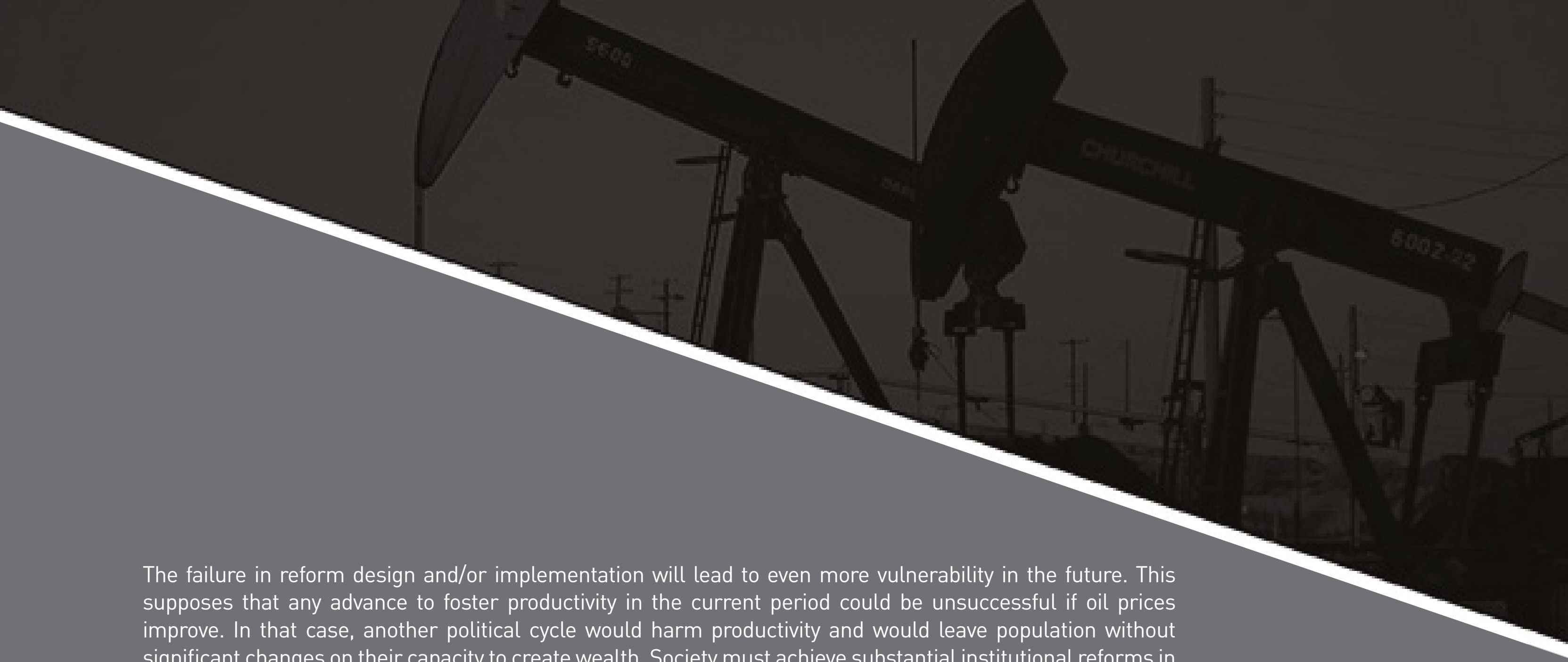
This methodology also covers the feasibility of diversification by observing the "distance" of current exports and more complex ones. Approaching to more feasible and complex goods allows to add value to exports by benefiting from prevailing enclaves: commodities in our case. This is a work yet to be done in Venezuela, shaded by denying the role of oil and the natural resources in productive development.

There is a pending issue regarding not to "sow oil" but to sow in oil: produce and export knowledge, technology and services related to the commodity and its derivatives. The oil-related chain can actually generate development. In order to promote it, there is a necessity of economic openness to individuals with the knowledge and capacity to be competitive in international markets. Not all resource-abundant countries are exposed to the commodities prices cycles. Needless to say: there is not anything inherently wrong with the Venezuelan economy. Oil is not a sentence against the country, if its effects are isolated from political and economic cycle through well designed institutions.

The long and winding way: institutional ties

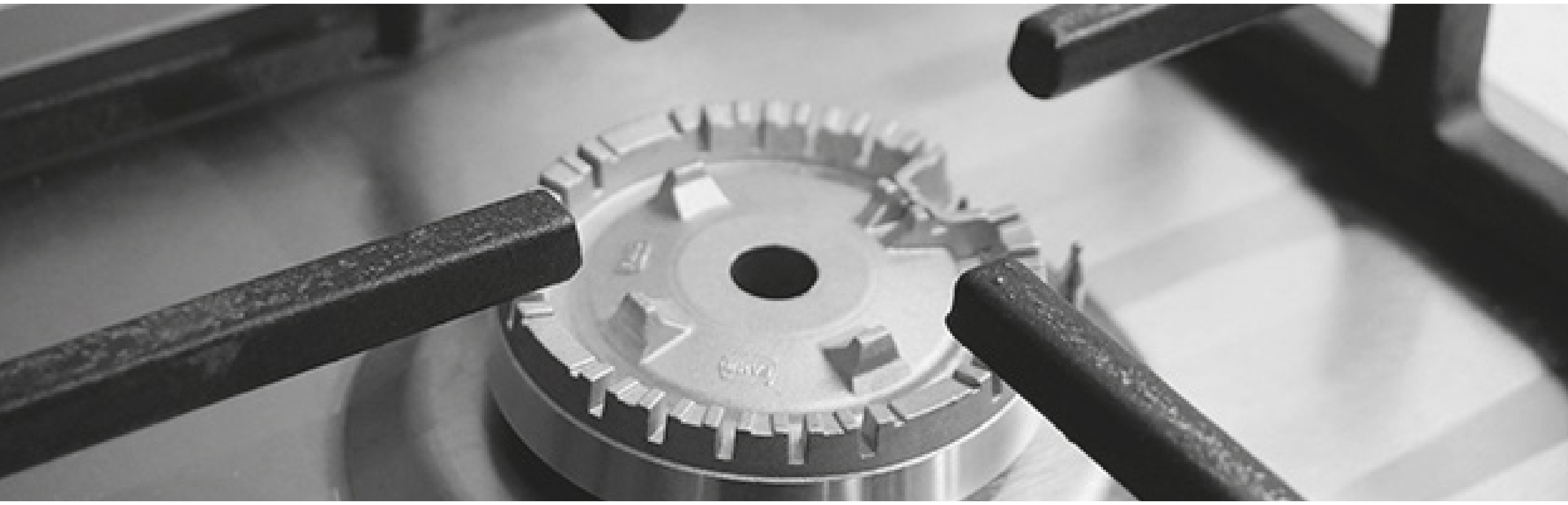
In their book "El Petróleo como Instrumento para el Progreso" (The Oil as an Instrument for Progress), Luis R. Rodríguez and Pedro L. Rodríguez potted into a metaphor the problem. As they posit, oil rents are like siren songs. They compare the problem of oil rents with Homeric history of murderer sirens that attracted sailors by singing beautiful songs. In order to survive, the heroe is tied to a mast. By being tied, Odysseus enjoys hearing songs and survives, succeeding to a life-threatening situation. "Sirens songs" of oil rents require ties or, in economic and political terms, institutions, in order to avoid its own threats.

Institutions can break the economic and political vicious circle by modifying the incentives that lie behind them. The goal must be to control public discretion in the use of resources. Government authorities must be less capable to use oil income for political aims. In order to achieve it, oil has to be understood as far more than a merely fiscal source of income. Besides, since the oil industry nationalization, the country is indebted with Venezuelans as national private sector is not a major player in the business. Venezuelans who started business in crude oil extraction and today could export their knowledge and technology as a product with high added value. It is a debt with citizens to allow their participation into hydrocarbon sector. Even further, this allows to change the citizen-state relationship in order reduce the role of the State in resource income allocation. Today, with low oil prices, we have a historical opportunity to drive a set of reforms in order to advance into a long term development path, far from dependence and volatility typical cycles.



The failure in reform design and/or implementation will lead to even more vulnerability in the future. This supposes that any advance to foster productivity in the current period could be unsuccessful if oil prices improve. In that case, another political cycle would harm productivity and would leave population without significant changes on their capacity to create wealth. Society must achieve substantial institutional reforms in order to take a rough but virtuous path: commodities independence. Above all, these reforms will need political maturity towards moving forward and not to abandon the path after brief steps, just like in the 1990's.

Artículo publicado en Prodavinci. Disponible en: http://prodavinci.com/2016/03/15/actualidad/el-largo-y-tortuoso-camino-de-la-renta-petrolera-por-diego-guerrero-2/



Gas sector

Tabla 6 Gas sector in 2014

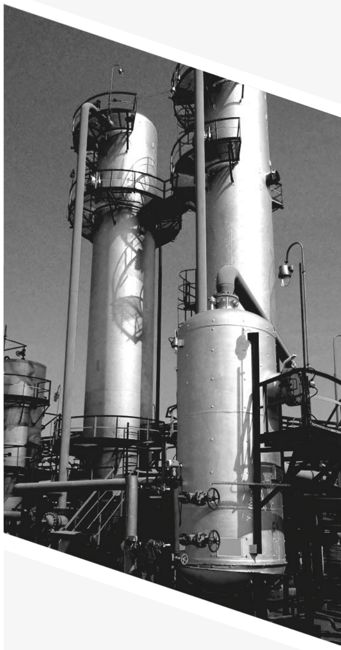
	RESERVES (BCF)	PRODUCTION (MCF)	CONSUMPTION (MCFD)
WORLD	6606.45	334.82	328.28
CENTER AND SOUTH AMERICA	270.63	16.93	16.45
VENEZUELA	197.09	2.77	2.97

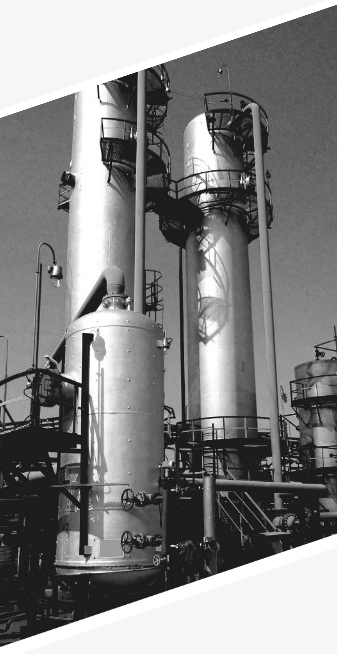
Fuente: Statistical Review of World Energy (BP, 2015).

Tabla 7 Gas sector in 2015

	RESERVES (BCF)	PRODUCTION (MCF)	CONSUMPTION (MCFD)
WORLD	6599.40	342.40	335.60
CENTER AND SOUTH AMERICA	268.10	17.30	16.90
VENEZUELA	198.40	3.10	3.34

Source: Statistical Review of World Energy (BP, 2015)

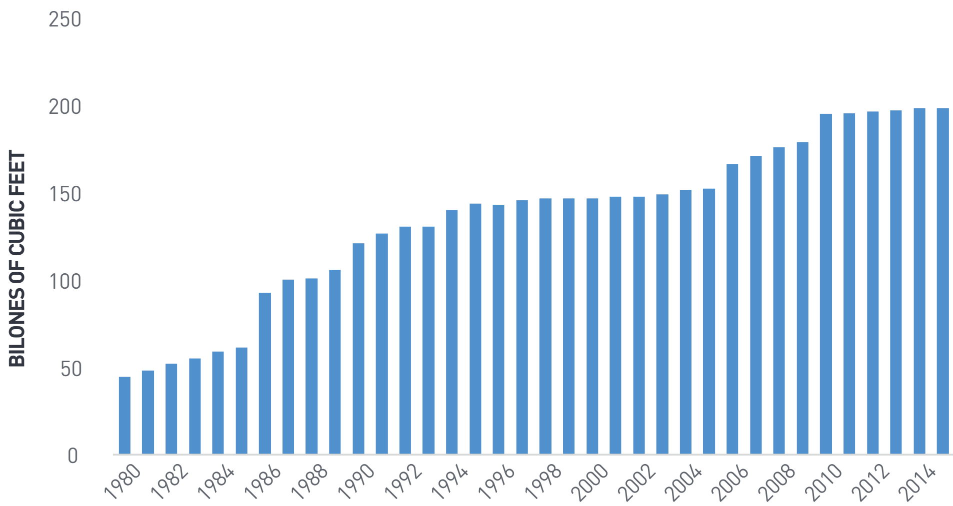




PROVEN RESERVES

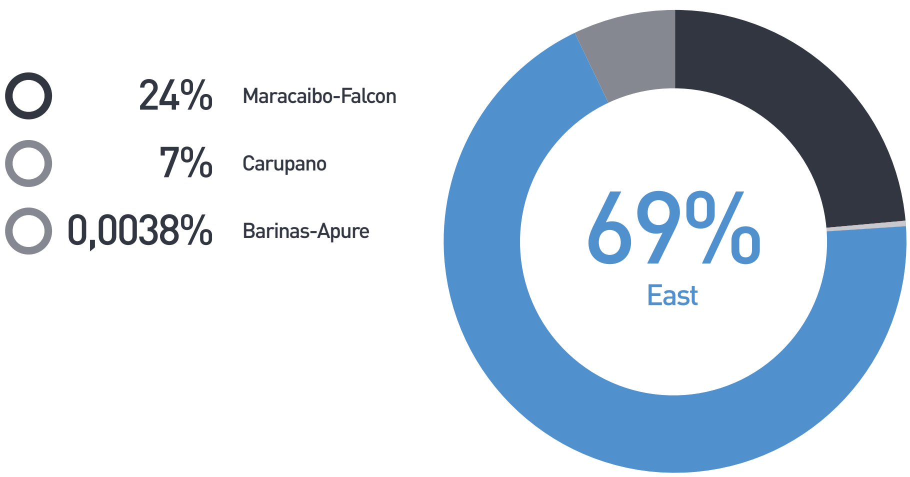
During 2015, official figures show 1% increment in natural gas proven reserves. Eastern basin accounts 70% of total gas reserves and Maracaibo and Falcon (west) has 23%. According to the Annual Management Report 2015 (PDVSA, 2016), 34% of produced natural gas is used for reinjection (7,756 mcfd).

Figure 48 Proven Reserves of Natural Gas, Venezuela (1980-2015)



Source: Statistical Review of World Energy (BP, 2015)

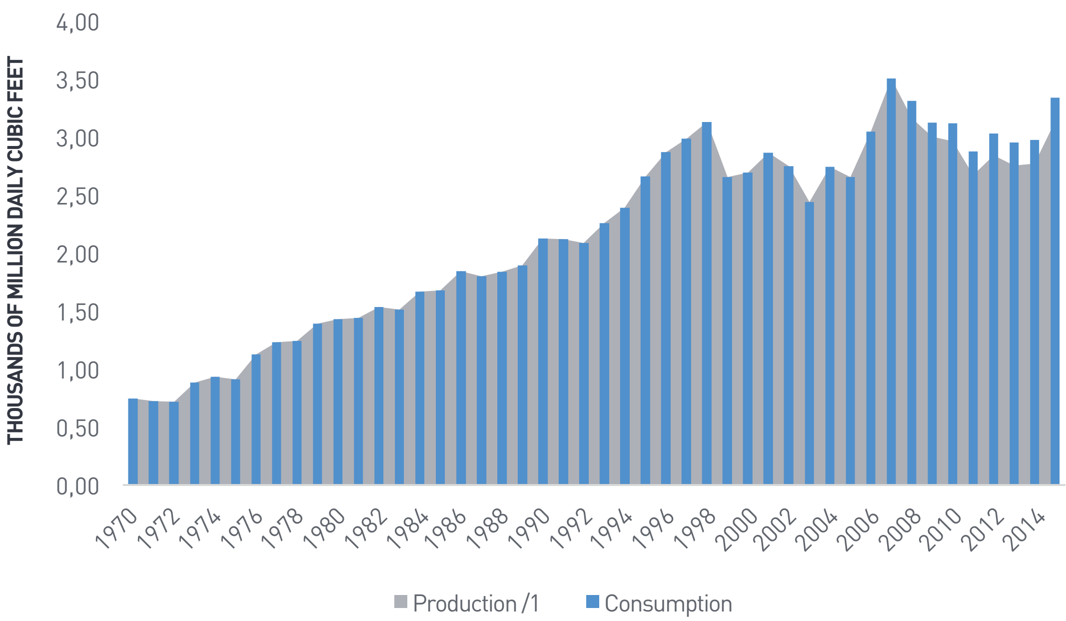
Figure 49 Gas Reserves Distribution Classified by Basin (2015)



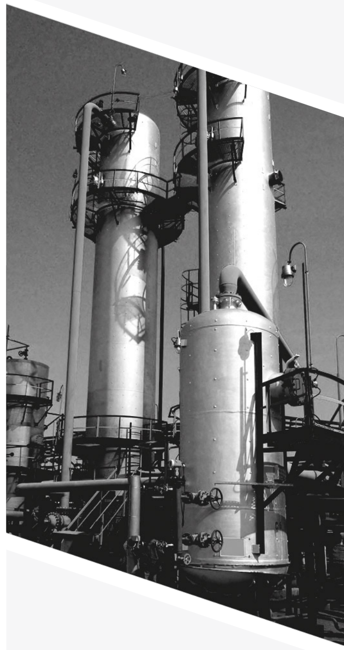
Source: Annual Management Report 2015 (PDVSA, 2016).

Exploration and Production

Figure 50 Natural Gas Production and Consumption, Venezuela (1970-2014)



Source: Statistical Review of World Energy (BP, 2015). 1\ Excludes flared gas. Includes natural gas produced to be converted into LNG.



Since 2011, natural gas domestic consumption exceeds domestic production and this difference grew until 2014, when the trend was reversed due to consumption decrease –which accumulated 323 mcfd–. After peaking in 2012, annual production grew 0.5% in 2014, reaching 2,760 mcfd in 2014, a 9.42% slump as compared to 2012 maximum.

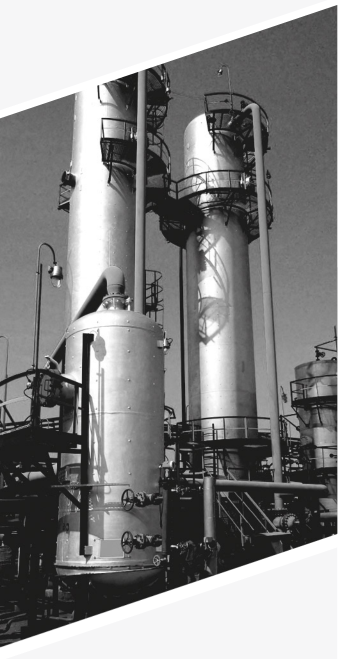
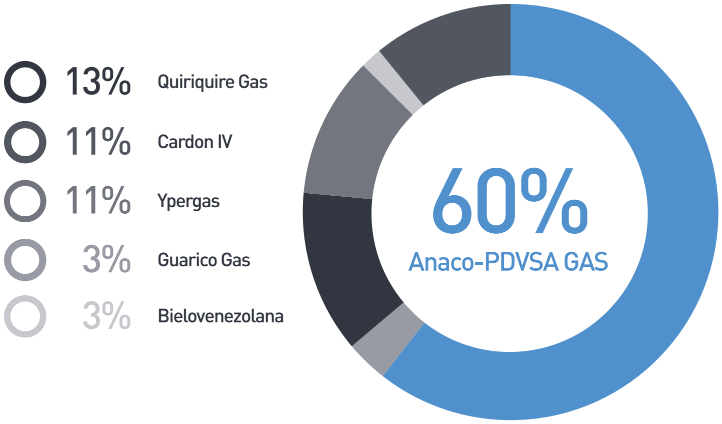


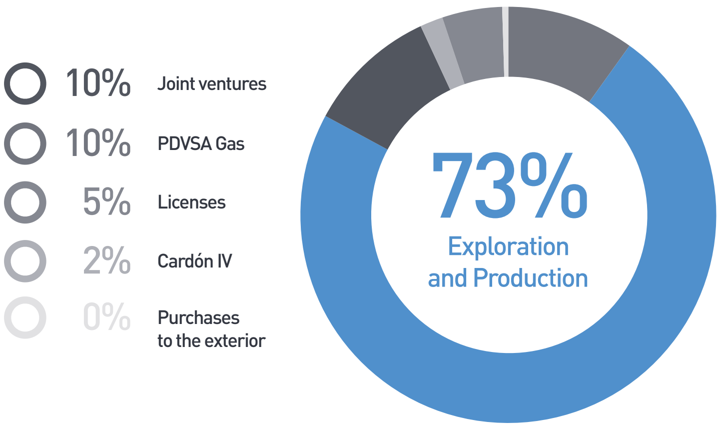
Figure 51 PDVSA natural gas production by region (2015)



Source: Annual Management Report 2015 (PDVSA, 2016).

More than half of total non-associated gas and LNG production came from Anaco, which was 795 mcfd in 2014. Other regions share less proportions of annual production, being Quiriquire Gas (173 mcfd) and Ypergas (111 mcfd) the most relevant. Assigned licenses produced 346 mcfd during 2014.

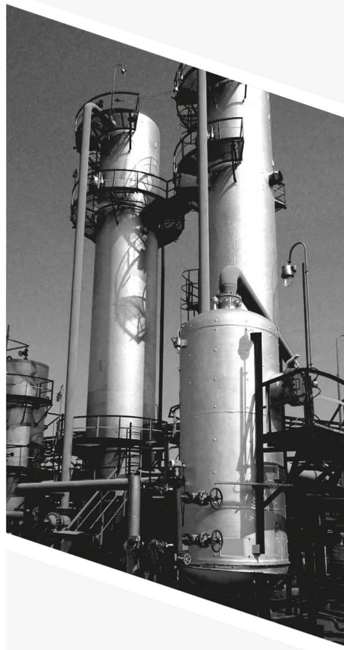
Figure 52 Natural Gas Availability by Source



Source: Annual Management Report 2015 (PDVSA, 2016).

Most of natural gas availability is associated to exploration and production, with over 5,402 mcfd coming from oil related activities. Besides, during 2014 more than 94 mcf were imported from Colombia, through the Antonio Ricaurte gas pipeline. From total available production, 5,2013 mcfd were destined to supply PDVSA's internal consumption (70.1%), 171 mcfd were transformed to LNG (2.3%) and 2,048 mcfd were consumed by domestic market (27.6%).

Current status of gas projects

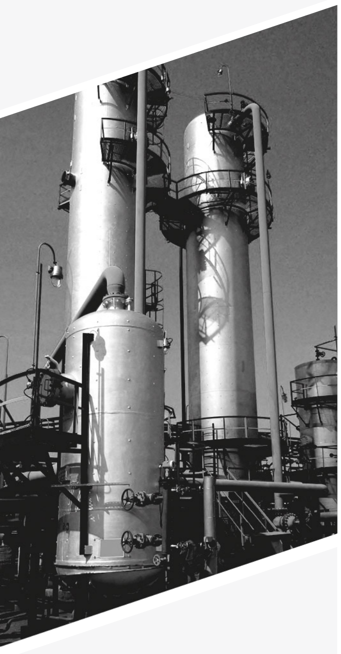


Mariscal Sucre and Rafael Urdaneta projects showed advances in production performance during 2014. Off-shore Sucre development accounts a production of 190 mcfd with an expected level of 300 mcfd. The gas pipeline Dragon-CIGMA has 90% of advancement and 78% in pipe-rack installation and other facilities for PAGMI plant. On the other hand, the development of twenty-one more gas wells has been a completion rate of 83% in the Main Platform, with a production goal of 450 mcfd in 2015.

Table 8 Natural gas projects status (2015)

PROJECT	GOAL	STATUS
MARISCAL SUCRE	Off-shore development, east. **Production goal: 1,250 mcfd** gas and 28 tbd condensates.	Accelerated production scheme, 84% ongoing out of 300 mcfd.
RAFAEL URDANETA	On-shore development, west. 30.000 km2 and 9,500 mfd gas. 21 wells are planned in Mio Perla field at Cardon IV project.	Main production platform (PP1) reports 83% of progress.

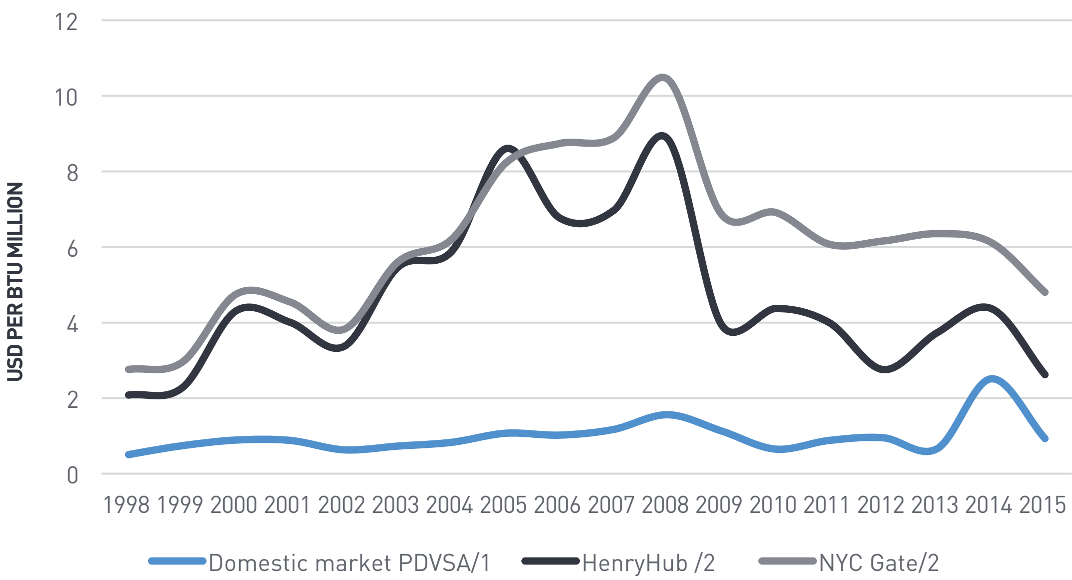
Source: Annual Management Report (PDVSA, 2014).



Natural gas prices

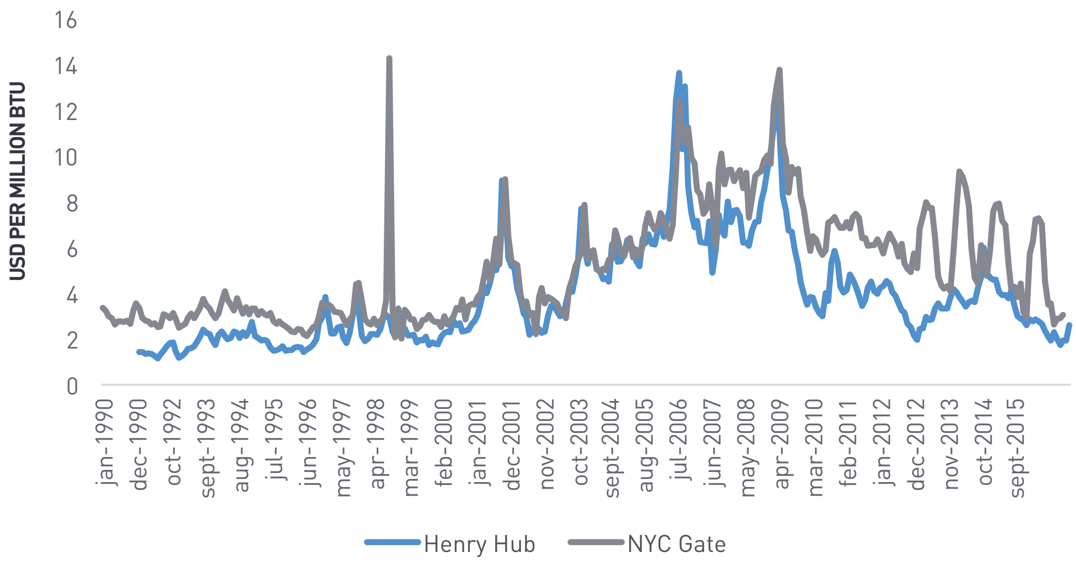
International natural gas prices began a steady decline since 2008, as measured by Henry Hub and New York City Gate benchmarks. Nonetheless, given the current regulations for domestic markets in Venezuela as well as the effect of exchange rate scheme effects, domestic gas prices have been well below both benchmarks. After a minimum of 0.68 USD per mBtu, PDVSA reported 2.4 USD per mBtu 2014.

Figure 53 National and international natural gas prices (1990-2015)

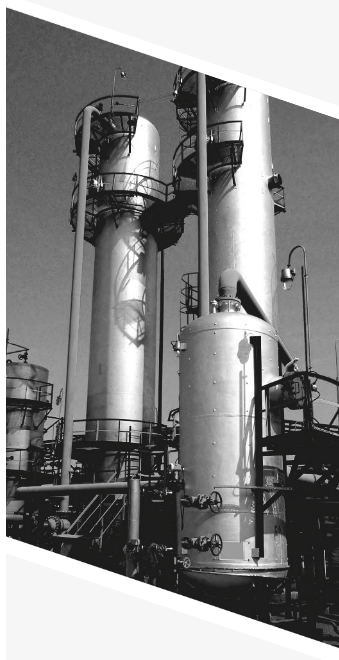


Source: International Energy Statistics (EIA, 2016), Statistical Review of World Energy (BP, 2015), Management Report (PDVSA, various years) and PODE (MENPET, 2012). 1\ Weighted average. Conversion factor of 1,028 BTU per gas cubic foot. 2\ Simple average of daily and monthly prices.

Figure 54 Natural Gas Prices, International Benchmarks (1990-2015)



Source: International Energy Statistics (EIA, 2016), Primary Commodity Prices (IMF, 2016).



In the short run, international gas prices have a downward trend. New York City Gate price reduced its average from 6.35 USD per mBtu in 2013 to 2.63 USD per mBtu in October 2015. Henry Hub benchmark also fell to a minimum historical close of 1.93 USD per mBtu in December 2015, from an average of 4.37 USD per mBtu in 2014 and 2.63 in the same year.

BOX

/5

WHY DID VENEZUELA STOP IMPORTING NATURAL GAS FROM COLOMBIA?

- BY ARMANDO FLORES & IGOR HERNÁNDEZ -

On June 25th 2015, PDVSA announced in a press release that Venezuela would stop natural gas imports from Colombia in July. Such decision was originally expected to occur in 2011, but due to local project's delays, supplying contracts were renewed by the NOC several times in order to cover the energy deficit in the country's western region.

Even though PDVSA argues on irregularities in supply held by the Colombian counterparty (which is true), it does not seem to be the sole basis. As of July 2015, one of the biggest gas projects in the country starts to operate: Cardon IV. This mega project is not only expected to meet the domestic deficit, but is intended to allow PDVSA to export gas to Colombia in the short term.

1. The roots of the exchange: a gas supply agreement in two stages. In May 2007, PDVSA entered into a supply agreement with Colombian NOC Ecopetrol and Chevron, designed to exchange methane gas through the Antonio Ricaurte gas pipeline. The first phase of the huge pipeline, which covers an extension of 225 km, was financed through PDVSA and connects the Ballena Field in Colombia to Termozulia and Urdaneta thermo-electric plants in Maracaibo.

The contract was structured in two parts: Colombia would start by exporting gas to Venezuela during four years and later make a reversion in gas stream in 2011, when Venezuela would deliver gas back. Both nations would be benefited from this agreement. Colombia placed its current surplus and got prepared to cover its future deficit. On the other hand, Venezuela would not only meet its current deficit but could ensure a market to place part of the gas from new projects, expected to come into operation by 2011.

2. The ideal candidate: Rafael Urdaneta project. In this context, the Rafael Urdaneta Project, in the western state of Falcón, became relevant. This is one of the main projects in off-shore non-associated natural gas, along with Mariscal Sucre and Deltana Platform, in Sucre and Delta Amacuro states. Due to its proximity to Maracaibo, Rafael Urdaneta was ideal to "connect" Antonio Ricaurte gas pipeline and supply gas to Colombia. The project consist of 29 blocks, of which 18 are located in the Venezuelan Gulf and 11 in northeast Falcón. One of the blocks turned out to be promising, given that accounts on more natural gas reserves than entire countries such as Colombia or Bolivia.

3. Cardón IV and Perla, the biggest natural gas field in Latin America. In October 2009, the Spanish IOC Repsol announced the biggest gas discovery in its history: Perla1X, the first exploratory well in the Perla field located into the Cardón IV Block. The field had been estimated to have recoverable gas reserves of 6 to 8 billion cubic feet. The number was later on adjusted upwards close to 16 billion cubic feet, being not only the biggest discovery for the company with a 22 year trajectory and presence in more than 40 countries, but the most significant in the entire history of Latin America.

Repsol and Italian ENI created a joint venture in order to develop the block with equal share for each one (50%), as allowed by Venezuelan law on this regard. Nonetheless, the first phase was delayed. For this reason, in the absence of choices to meet gas demand for power generation, petrochemicals and oil production; PDVSA had to renew the supply contract with Colombia several times.

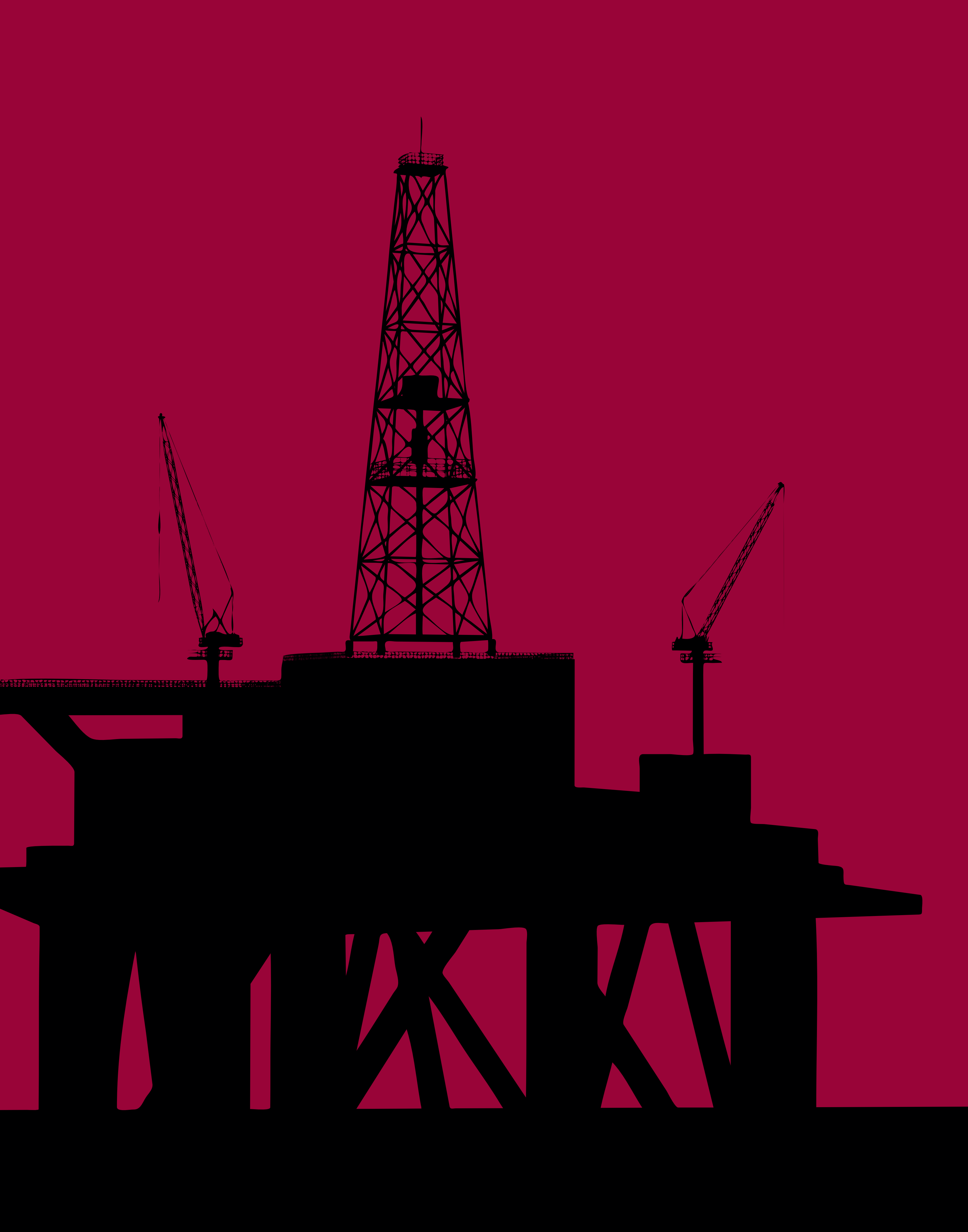
Project delays in Venezuelan fields were too expensive after extending for more than three years the imports of gas paid at international prices. It is estimated that PDVSA paid over 1,100 USD million to Ecopetrol and Chevron between 2012 and 2014 for this supply, more than 1 USD daily million in 2012 and 2013.

4. 2015: Perla finally starts to run operations. PDVSA payments should end in 2015, when finally Venezuela stops to import natural gas from Colombia, thanks to Perla commencement of operations. Such information has been confirmed by the NOC official spokespersons, as well as by Eni and Repsol. It is expected that the field starts with a production of 150 million cubic feet per day, to450 at the end the year and rise to 800 in 2018. This levels would not only meet imported flows from Colombia, but would also allow PDVSA to generate excess income by exporting surpluses back to Colombia.

5. Relevant questions to consider: When and how much gas could be exported to Colombia? According to the current agreement, PDVSA should start to export natural gas to Colombia in January 2016. It was stipulated to make initial deliveries of 39 million cubic feet per day, which are supposed to grow until 150 million cubic feet per day after four years. Still, additional contracts could be agreed for higher amounts, given the Antonio Ricaurte pipeline capacity of over 500 million cubic feet per day.

Will Venezuela export gas in 2016? Not necessarily. By being a take-or-pay agreement, once started the shipments, PDVSA will be obligated to send gas to Colombia, otherwise would cause a breach of contract. For this reason, the decision to export gas will be subject to the certainty that PDVSA can actually fulfill initial exports requirements or its willingness to be exposed to penalties. A fundamental issue on this matter is related to the completion of the connection between Perla and the gas pipelines system in Venezuela, in order to fill the transportation to the Antonio Ricaurte pipeline. Until the date, some progress have been made. But no gas molecule has already been exported to Colombia.

Artículo publicado en Prodavinci. Disponible en: http://prodavinci.com/por-que-venezuela-dejo-de-importar-gas-de-colombia-por-armando-flores-e-igor-hernandez-640/



A STRUCTURAL CHANGE IN PRICES

REGIME SHIFT IN OIL MARKETS

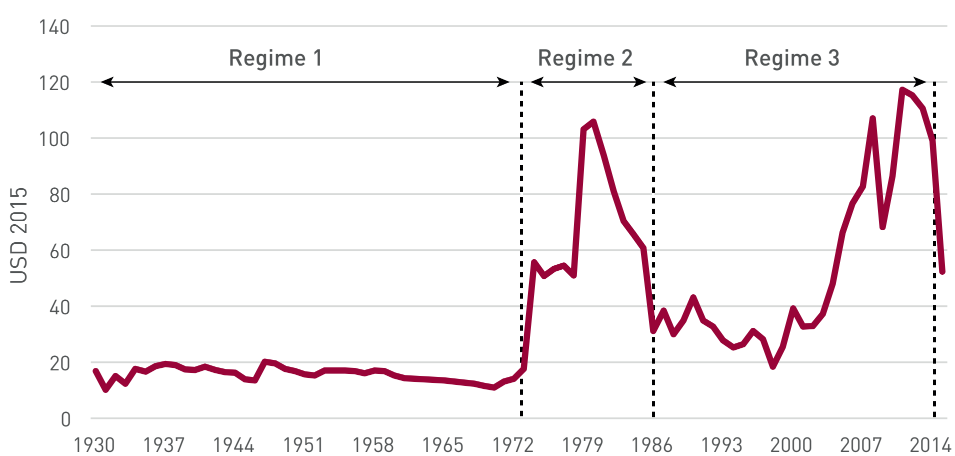
BY: LUIS ROBERTO RODRÍGUEZ PARDO

Oil market's structural properties make the price highly volatile and the mechanisms to reduce it have caused heavy losses to producers and consumers. On this regard, we can identify three different oil price management periods over time. They do not represent formal systems with explicit rules, but common understanding parameters between major players who seek to manage market intrinsic volatility. In this article, we resume the main attributes of these regimes, their successes and failures, as well as the backgrounds of the new regime, which started by the November 2014 decision in the OPEC to maintain its price level despite prices weakness since.

First Regime: The Seven Sisters

The first existing regime operated from 1930 to 1973. It was controlled by seven to eight major oil companies, the so-called "Seven Sisters", and complemented by two government agencies: the Texas Railroad Commission and, later on, the Interstate Oil Compact Commission. The former two coordinated internal United States production, imports and exports of crude oil. During this period, the US was the main producer and a relevant exporter of oil. Nonetheless, domestic marginal costs of production were historically higher than other oil provinces like Venezuela and the Middle East.

Figure 55 Crude Oil Prices, 2015 US Dollars (1930-2014)



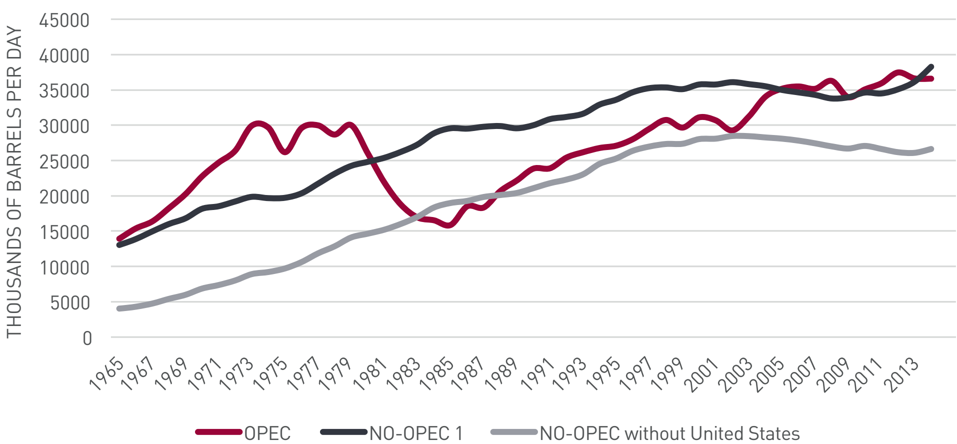
Source: BP Statistical Review of World Energy

During the first regime, major oil companies fixed international prices in order to preserve the United States' production feasibility, which made production very profitable for the lower-costs provinces. By means of associations, long term supply agreements and tacit consent, production volumes remained in levels which held stable posted prices. The OPEC strengthening, the oil price shock of 1973 and the nationalization of concessionary companies led to the end of this period. By far, the first regime has been the most successful and resilient in terms of price stability, as shown in the Figure 54.

Second Regime: The OPEC

The next price management scheme was briefer than the previous, going from 1974 to 1985. In this case, reference prices were fixed unilaterally by the OPEC, which became the dominant player in the market. Nonetheless, OPEC countries agreed to fix prices according to their fiscal requirements, well above marginal cost levels. This trend favored non-OPEC production growth in new provinces, such as Mexico and the North Sea. As a consequence, OPEC turned into a residual producer, whose offer is taken after the remaining players produce at full capacity levels. At the same time, nationalization of foreign concessionary companies removed the supranational coordination mechanism that worked in the past regime, intensifying rivalries inside the OPEC. As Yamani once stated: "companies act as buffers to protect members from destructive competition."

Figure 56 Oil Production, OPEC and Non-OPEC Countries



Fuente: BP Statistical Review of World Energy, 2015. 1 Countries of the former USSR not included.

Additionally, sudden hikes in prices forced net importer countries to embrace coordinated actions in order to reduce consumption and promote the substitution of oil for other energy sources through new regulations and tax increases to oil-related products.

To be sustainable, some conditions were needed. OPEC accounts on two instruments to influence: prices and volumes. But they are not independent each other given their relationship through a crude demand curve. Hence, it was necessary to choose only one parameter as target and the other as an instrument to meet it. Both market share and prices are not possible to defend simultaneously. In face of a weakening demand growth, both options are painful. To OPEC, defend prices means to make significant cuts in production, as occurred back in 1979 and 1985. Figure 55 illustrates both episodes.

To defend market share usually leads to a price war which tends to conclude in sudden slumps in international oil prices, as it was the case in December 1985 and September 1986. In order to stabilize the market, OPEC must undertake three difficult tasks: decide clearly the target to defend, price or market share; split the market into the different members and establish credible and enforceable commitments. This is hard work to do for sovereign states.

Traditional OPEC target has been to defend prices, sometimes without taking into account the market share losses related to it. The organization's first production quota was established in March 1982, but soon inconsistency in defending prices or fixed shares was clear. By March 1983, total production decrease in half a million barrels per day, and new fixed production quotas were assigned to all members but Saudi Arabia, which was aimed to adjust production according to market conditions (act as swing producer). All these measures concentrated the whole load of adjustment to Saudi Arabia, which saw its production decline in almost two thirds from 10.26 million barrels per day to 3.60 million barrels between 1981 and 1985. But the impact was still higher in terms of income, as it decreased over 80% due to prices and production impacts combined. This experience left an indelible mark in Saudi leadership, which now rejects to act as swing producer again. Furthermore, the new Saudi position claims to share any production cut even with non-OPEC producers, in addition to the organization's members.

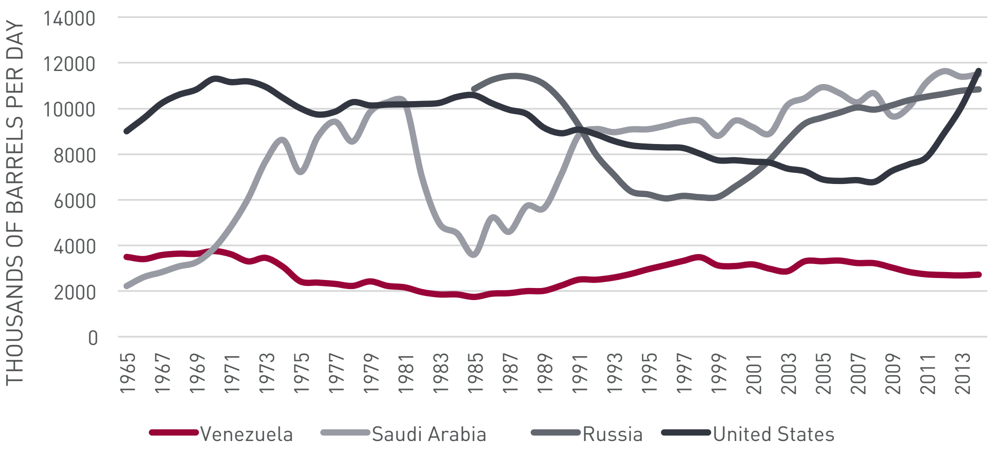
The second regime collapsed by the end of 1985, when Saudi Arabia abandoned the price defense strategy on behalf of its market share and adopted the net back pricing mechanism. This strategy was successful to increase Saudi Arabia's production levels, which rose to over 9 million barrels per day between 1985 and 1992. However, prices fell dramatically from 27.12 to 10.91 USD per barrel between July 1985 and November 1986.

We must emphasize that price defense at the expense of market share involves a paradox in the medium term. Progressive share losses makes even more difficult to defend prices as bigger cuts are needed in order to influence the market. Price defense leads to decreases in OPEC's market share which leads to less market power. Thus OPEC came to control only 27.62% of world production in 1985, down from 51.20% in 1973. This is clear in Figure 55.

Third regime: two markets

Third Price management regime starts with the prices collapse in 1986 and has evolved until then. This regime accounts on two separated components. The physical barrels market, in which producing countries' NOCs sell crude oil to traders and IOCs. Price setting in this market is based on benchmark crude oil prices such as Brent, Oman/Dubai or West Texas Intermediate. A second component, with a more reduced physical basis, comprehends spot and futures markets, where crude oil is traded in international stock exchanges (NYMEX, ICE). Price formation in this market is made on a price formulae basis. Financially traded volumes in financial markets exceed significantly physical traded volumes. For instance, in 2010 daily average traded volumes in NYMEX and ICE were 950 million barrels per day, as world daily production was 83.3 million barrels per day . This gap can actually blur real market fundamentals.

Figure 57 Oil Production, Selected Countries (1965-2014)



Source: BP Statistical Review of World Energy

New regime: Discovering the marginal barrel price

Everything took an unpredicted turn in November 2014, when a Saudi Arabia-led OPEC decided to maintain its production levels in spite of the decline in prices starting in June the same year. The decision to defend market share over prices suggests a shift in market regime as OPEC refuses to be the swing producer nor the first to cut production.

In order to understand Saudi Arabia's decision, Figure 55 shows how non-OPEC production –excluding the U.S– declines since 2002. Now, as noticed in Figure 56, the U.S. production starts to rise in 2008, after four decades of contraction, growing by more than 4.4 million barrels per day or 65% since 2002. Only in 2014, U.S. production rose in 1.2 million barrels per day or 16.2%, a historical record that turned the country into world's largest producer[5] . This rapid increase is mostly due to shale oil developments. Shale is an unconventional oil with higher associated costs which has become profitable with recent horizontal drilling and hydraulic fracturing (fracking). Another relevant element is the availability of cheap financing costs as interest rates have remained low. The industry gathered, accounting on equity and debt, 875 USD million to finance exploration and production investments between 2007 and 2014[6].

There are three features in shale oil that distinguish it from conventional ones. First, its early development is faster, being less than six months as compared to three to seven years for conventionals. Second, extraction costs in a shale oil well are only a fraction of other unconventional, such as wells in off-shore fields. Third, its rapid depletion –from 60% to 90% in the first year– forces continuous drilling in order to sustain production levels[7].

Technological advance, availability of funds, fast production response, low costs per well and accelerate declining have turned shale oil production into a process close to industrial standards. This flexibility allows shale oil to respond faster to market fluctuations than conventional ones[8] .

5 Energy Information Administration, www.eia.gov/todayinenergy/detail.cfm?id=18831
6 Dealogic, www.ft.com/cms/s/0/96bd2cec-c258-11e4-ad89-00144feab7de.html#axzz3WAzIhH87
7 Shale oil depletion follows a hyperbolic function. During the first two years, a half of total volume is produced, with a second stage in which depletion occurs in 5 to 6% annual rates in near twenty-five years. Operating costs in the second stage are low and stable (5 to 10$ per barrel). Given the number of wells already in the second stage, there is a base production which will continue to flow even in face of low crude oil prices. It is important to remember that the decision to continue producing is related to operational costs and not to average costs.
8 Only in 2014 near 37,000 wells were drilled in the U.S. See Financial Times, www.ft.com/cms/s/0/372e52bc-c98b-11e4-a2d9-00144feab7de.html#axzz3W45Ybecv

OPEC perceives shale oil as a higher cost competitor. By the end of 2014 Abdalla El-Badri, the organization's general secretary, declared that 85$ per barrel price would threaten half of shale production[9]. Saudi minister Ali al-Naimi added: "it is not the role of Saudi Arabia and other OPEC countries to subsidize higher costs producers through our market share transfer"[10]. Additionally, a reduction in prices means a hard blow to Saudi's rival economies, such as Iran and Russia, already harmed due to international sanctions.

Clearly, Saudi experience of the first half of 1980's must have played a role on its decision. In this opportunity the kingdom faces a much more favorable situation. In the decade of 1980 the price fell during continuous years and finances showed an increasing deficit. This time a sustained high and stable prices era has allowed the country to collect over 750 USD billion in international reserves. Furthermore, oil demand showed an accumulated decrease of 13% between 1979 and 1985. Now, even when growth rates are expected to fall, demand will probably rise between 1.28 and 1.43 million barrels per day in 2015 and 2016, respectively.[11]

Even though it is early to assess Saudi's and OPEC decision, facts seem to support it. A cut in production would lead inevitably to a share transfer to non-OPEC producers, with lasting effects on prices. The lessons from the decade of 1980 may be well learnt. Prices slump of over 70% from June 2014 has been probably more pronounced than expected and production decline is starting to materialize. New investments in higher cost fields have been cut in more than 30% after price decline. Even so, production decline and demand growth are slow process, changing over the years.

Meanwhile, Saudi Arabia has taken a series of measures in order to reduce fiscal deficit, calculated in 15% of GDP in 2015 and estimated to close in 13.5% by the end of 2016. This would allow them to continue the current market share defense policy for a while. Measures include a 50% hike in gasoline prices, reduction of water and electricity subsidies, expending cuts, the introduction of the value-added tax and public enterprises privatization. Even an IPO of Saudi Aramco's shares is being discussed.

Another major event shaping the new prices regime is the recent decision by the United States government to allow crude oil exports, lifting a ban existing from 1970. In December 2015, the first shipping was made departing from Corpus Christi port in Texas. This is a major shift in American production over international prices. Until now, that impact was reflected on

9 Financial Times, www.ft.com/cms/s/0/64c2485e-70a4-11e4-8113-00144feabdc0.html#slide0
10 Financial Times, www.ft.com/cms/s/0/19801914-c673-11e4-a13d-00144feab7de.html#axzz3W45Ybecv
11 International Energy Agency, www.iea.org/oilmarketreport/omrpublic/

American imports reductions, which released crude oil volumes in international markets. Now the impact is straight. Relative crude oil abundance in the U.S. made the West Texas Intermediate benchmark to underperform as compared to European Brent benchmark. WTI discount on Brent peaked in 28$ per barrel in 2011, now being near zero after the ban lifting.

As exports are permitted, U.S. crude domestic prices rise, which is good news for American potential exporters, particularly shale producers. Finally, the U.S. could turn into a net crude oil exporter, which was impossible before due to exports restrictions and production decline.

Combining the shale oil production growth, U.S. exports openness and Saudi's market share defense position, we have a new price regime in which OPEC will not be the swing producer anymore. Progressive costs reductions in shale oil, which exceed 30% until now, and its production adjustment flexibility in the short term will provide more stability to the market and a probable price range between 35 and 65 USD per barrel. This will be the landscape unless unpredictable events happen, which is usual in international oil markets.

VENEZUELA'S O&G OVERVIEW

PDVSA: 10 ALARMING TRENDS
BY FRANCISCO J. MONALDI

Venezuela's extraordinary resource endowment and favorable oil price situation during the last decade, which despite its recent slump still remain historically high, contrasts with several alarming trends faced by the national oil industry that demand strategic actions.

1. Production decline in a period in which it should have increased rapidly. All sources differ over production levels in Venezuela, but everyone agrees to conclude that the country produces much less oil than 1998's peak or even than 2008's level. Conservative estimates show a decrease of 750 thousand barrels per day as compared to its historical high (near 25% drop), when an increase of more than two million was originally planned. In the same period almost every relevant oil market players raised their production, taking advantage on the high profitability caused by higher prices. Thus, Venezuela's market share has fallen significantly (35% from maximum) and the country has the lowest production-to-reserves ratio in the world.

2. Conventional crude oil production decrease more than proportionally to total production decline, particularly in light and medium crudes. Partially offset by Orinoco Oil Belt production growth. In 1998, heavy and extra-heavy crude oil production represented near 30% over total, and today is close to 60%. The decline of traditional areas has extended for over a decade. In the Lake of Maracaibo production has declined more than 30% and North Monagas most productive fields (particularly El Furrial) have deepen the decline in recent years, as production has collapsed in more than 25% in the last four years. This is a trouble spot since these have been the most profitable fields historically, PDVSA's cash cows. Besides, lighter crudes are necessary to dilute extra-heavy crude coming from the OOB, which is the only growing region. Thereof the country has been importing lighter crudes from Africa and the U.S. as diluents. As a result, Venezuelan basket is increasingly heavier and less profitable.

3. PDVSA's direct managed production has been declining faster than total production, as joint ventures production has increased slightly. This implies a reduced cash flow to PDVSA, as its partners account on until 40% of JV's equity. PDVSA's independent production drop from 80% in 2000 to less than 60% out of total today.

4. Net oil exports drop more than proportionate than production decline. Growing domestic market consumption, smuggling and crude oil imports have caused the loss of over one million barrels per day from its peak in 1998 (a 40% fall). In this sense, oil production are even less valuable for the country.

5. Almost every exports cut occurred in the most profitable market for Venezuela: the United States. At the same time, alternative exports destinations can't offset related losses. Growing exports to Latin American and the Caribbean highly subsidized as Asia reports lower margins due to transportation costs.

6. Most of exports to Asia are related to Chinese credits and are unable to generate cash flows to PDVSA. Only 1.4 million barrels per day, slightly over 50% out of total, originate real cash income to the NOC.

7. Operating and financial trends are also alarming, even before price slump. Production per worker has collapsed by more than 70% since 2001, as the result of an explosive payroll growth and the production decline. Costs per barrel have grown considerably, explained partially by official exchange rate appreciation but by remarkable efficiency losses.

8. PDVSA's external financial debt has grown vertiginously from 3 USD billion in 2006 to over 45 USD billion in 2014. The amount does not consider liabilities with providers, partners, expropriated companies or the Central Bank. The debt with the monetary authority exceeded 800 VEF billion by the first half of 2015. Exponential indebtedness expansion, during booming prices, was not translated into significant investment increases, as its destination was essentially public expenditure financing.

9. E&P investments have stalled in real terms. In fact, total operating rigs declined to a daily average of 64.5 during the first half of 2015, coming from 68 in 2014 and 72 in 2013. These figures are far below historical levels which could be over 100 rigs when production grew.

10. Finally, crude oil price collapse constitutes the latest but most devastating circumstance for PDVSA and the country.

These are a few alarming trends faced by PDVSA and Venezuela's oil industry. Excluding oil prices slump, none is new. All of them have been happening for years, but were hidden by the spectacular oil price hike revenues. Starting with the collapse of the price in 2014, PDVSA's control panel gives warning signals. At the same time, Venezuelan State, which increasingly depends on oil income, is in emergency too. Consequently, the last cannot easily reduce its resource demands over the former.

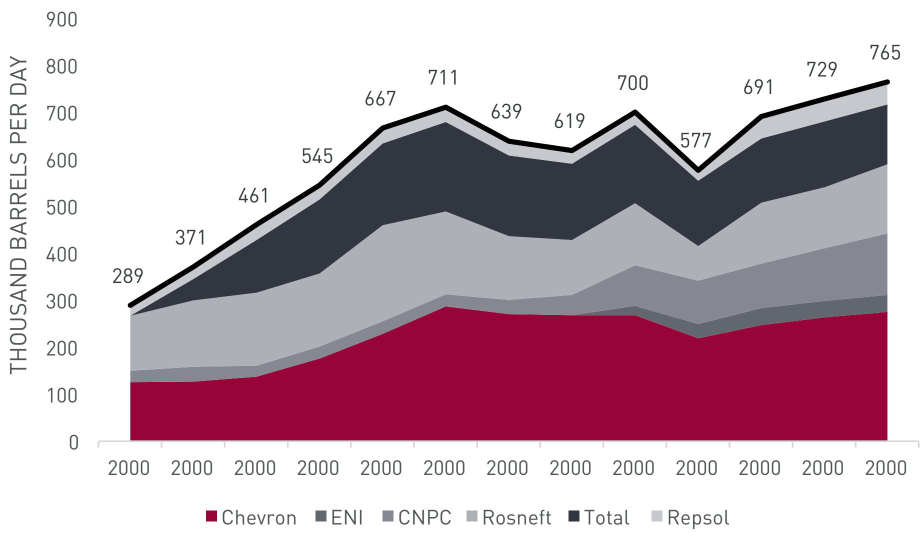
It is fair to highlight that PDVSA has recently turned into a more pragmatic policy, trying to mitigate some negative trends. OOB production has been raising, offsetting partially light crudes drops. Subsidized exports to the region have been reduced. Relationship with JV partners has improved. But a clear recovery strategy for PDVSA and the whole sector is far from being formulated. Despair or pragmatism, truth is that the government is trying to turn. Nevertheless, the damage caused to the national oil industry, precisely when having the best prospects, is immeasurable and hard to repair.

A new oil strategy is imperative, which intends to be adapted to current national industry and international market reality and reaches a social consensus. This will be an essential part in the country's recovery.

KEY PLAYERS IN THE ORINOCO OIL BELT

Into the group of Joint Ventures constituted in Venezuela, six international oil companies amass 89% of total crude oil production: Chevron, ENI, CNPC, Rosneft, Total and Repsol. Production figures for these JVs rose 765 tbd in 2012. Chevron is leads in crude production and CNPC is the company with highest production growth in 2000-2012. Only Rosneft has shown a production increase lower than 100% in that period.

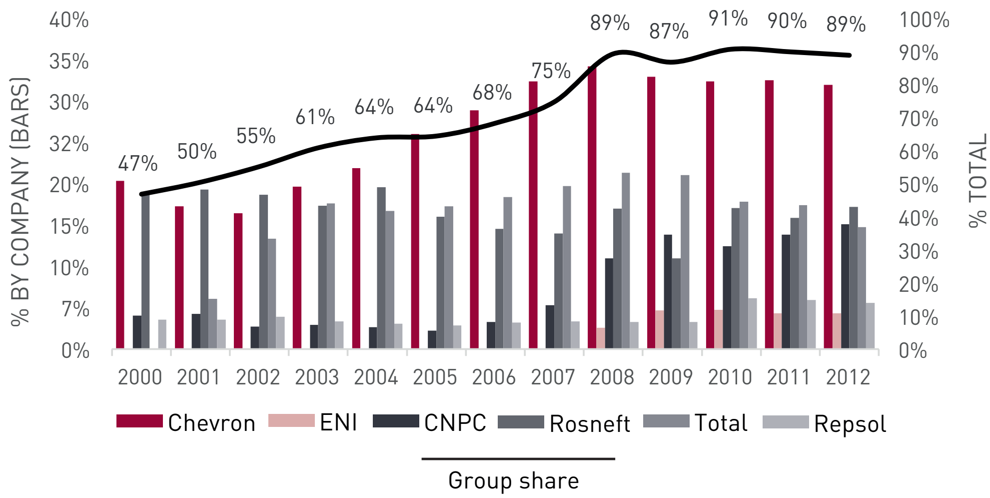
Figure 58 Joint Ventures crude oil production, selected partners (2000-2012)



Source: PODE (MENPET, 2012) and CIEA.

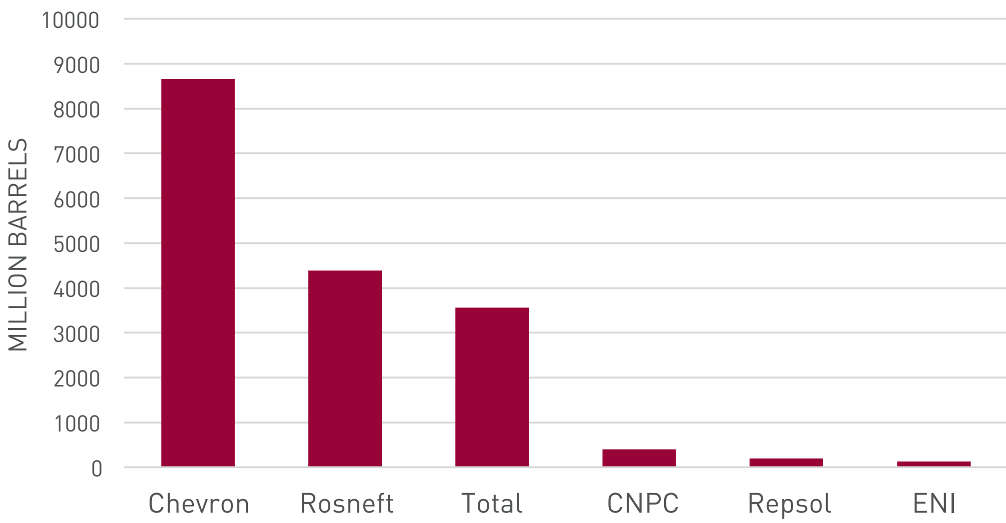
The assets into which these companies develop its operations and its contractual terms are heterogeneous. From 765 tbd total output, 30% corresponds to partners type B, according to their participation into the JVs. The decomposition by JV of the reserves awarded –in accordance with several sources– allows to identify three big players: Chevron, Rosneft and Total.

Figure 59 Key Players share in Joint Ventures crude oil production (2000-2012)



Source: PODE (MENPET, 2012) and CIEA

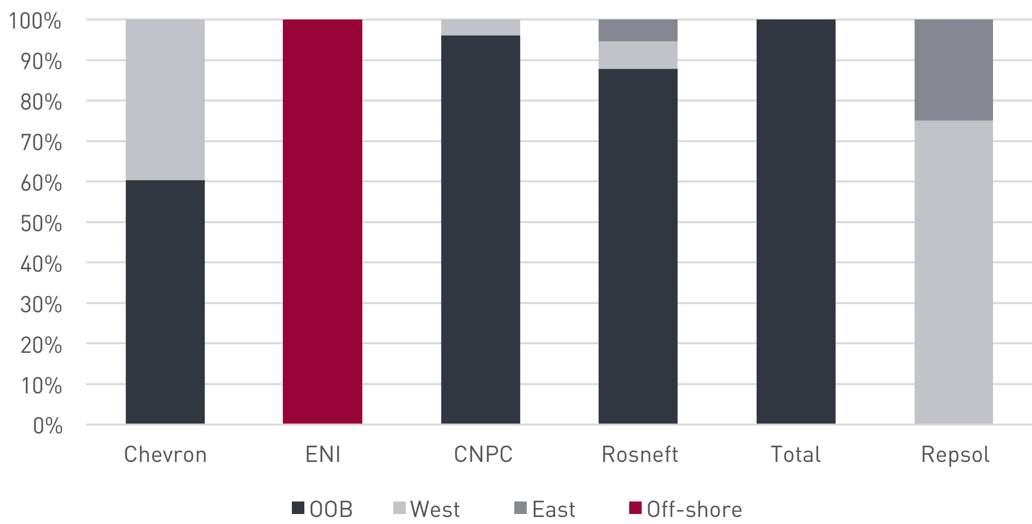
Figure 60 Proven reserves awarded to Joint Ventures partners type B



Source: PODE (MENPET, 2012), Annual Management Report (PDVSA, various years), Press Centre (PDVSA, 2007), Reporte Especial (Veneconomia, 2006).

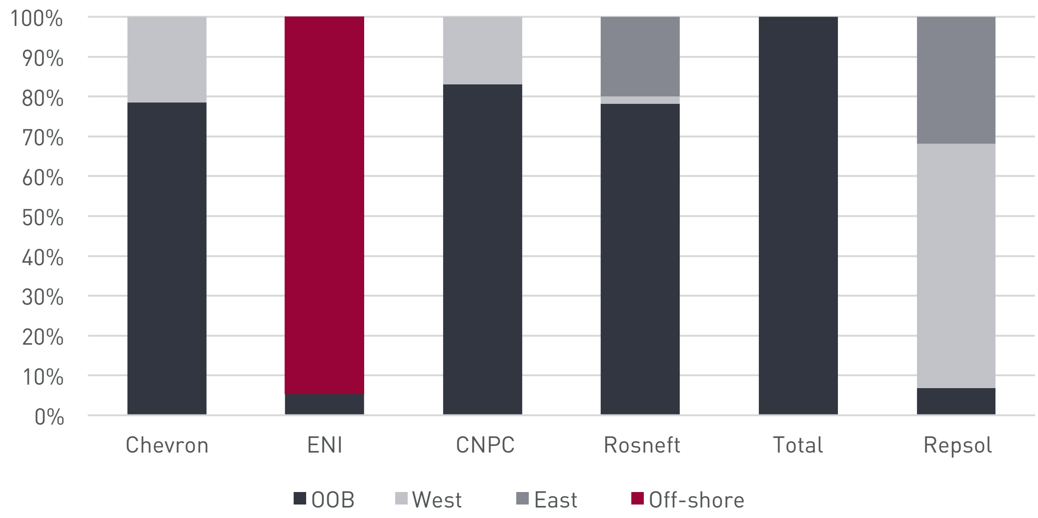
In terms of its assets profile, each key player has a portfolio with a diversification strategy for every division. In the OOB, the role of CNPC in Petrourica, Petrolera Sinovensa, Petrozumano and Petrolera Sino-Venezolana stands out (125 tbd oil production as of 2012); Total in Petrocedeño (127 tbd as of 2012); Rosneft in Petromiranda, Petromonagas, Petrovictorio (130 tbd as of 2012) and Chevron in Petropiar (166 tbd as of 2012) and Petroindependencia development.

Figure 61 Production by division, key players (2012)



Source: PODE (MENPET, 2012).

Figure 62 Reserves by division, key players



Source: PODE (MENPET, 2012),

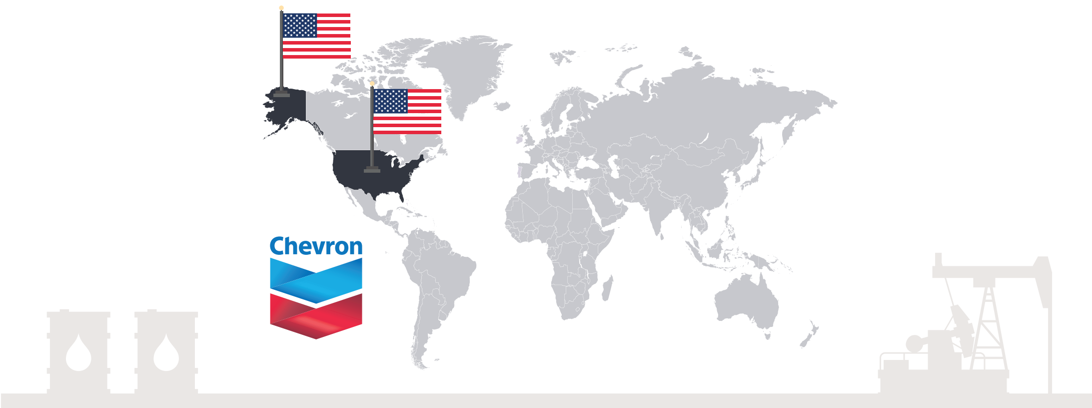


Table 9 Chevron: Company profile

COUNTRY	United States
FOUNDATION	1879
SHAREHOLDER STRUCTURE	International Oil Company
OUTSTANDING SHARES	100%
CHAIN VALUE SEGMENT	Exploration and production, refining and commercialization
WORLDWIDE	United States, Argentina, Brazil, Canada, Colombia, Trinidad and Tobago, Venezuela, Angola, Chad, Congo (Dem. Rep.), Congo (Rep.), Nigeria, Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, Myanmar, Philippines, Thailand, Australia, Saudi Arabia, Kuwait, Denmark, Netherlands, Norway, United Kingdom.
TOTAL RESERVES (2014)	5,511 MB
TOTAL PRODUCTION (2014)	2,571 MBOE per day
JV SHARES IN VENEZUELA	• Petroindependiente, S.A. • Petroboscán, S.A. • Petroindependencia, S.A. • Petropiar, S.A.

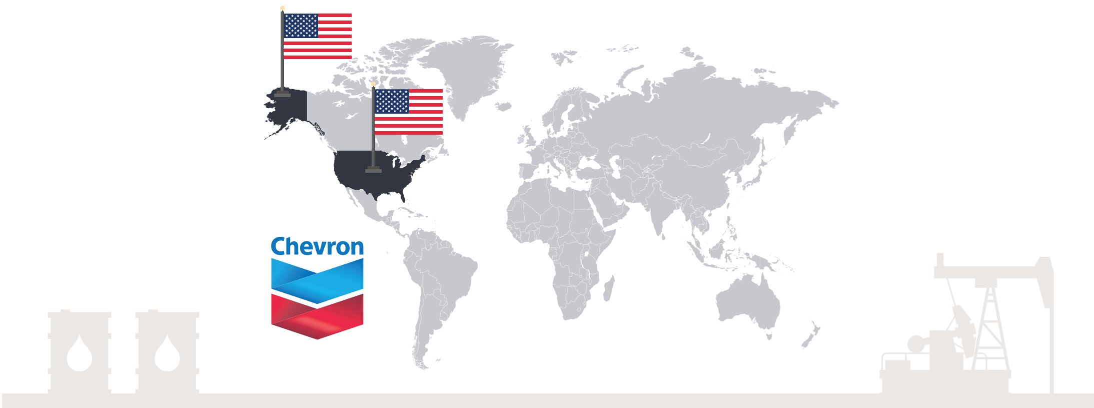
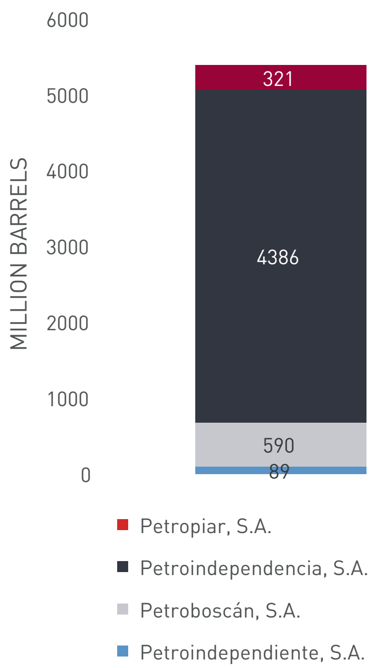


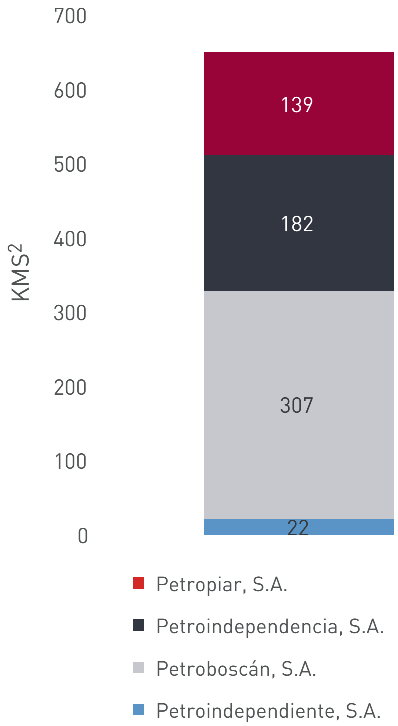
Table 10 Chevron Corporation: Asset profile

PETROINDEPENDIENTE, S.A. **LL-652**	**SHARE:** PDVSA: 74.80% Chevron: 25.20% Other partners: N/A. **West division:** Production (2012): 2 TBD Plateau: 19 TBD (2002)
PETROBOSCÁN, S.A. **BOSCÁN**	**SHARE:** PDVSA: 60.00% Chevron: 39.20% Other partners: Inemaka (Inepetrol, Venezuela) 0.80% **West division:** Production (2012): 107 TBD Plateau: 114 TBD (2014)
PETROINDEPENDENCIA, S.A. **CARABOBO-3**	**SHARE:** PDVSA: 60.00% Chevron: 34.00% Other partners: JCU (United Kingdom) 5%, Suelopetrol (Venezuela) 1%. **OOB division:** Production (2012): 0 TBD Plauteau: 360 TBD (2023)
PETROPIAR, S.A.	**SHARE:** PDVSA: 70.00% Chevron: 30.00% Other partners: N/A. **OOB division:** Production (2012): 166 TBD Plateau: 190 TBD (2005)

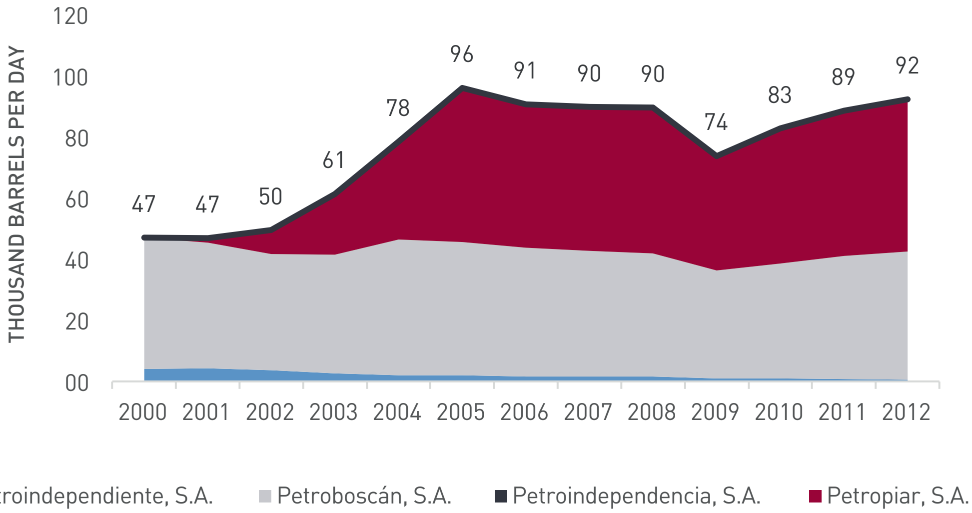
ATTRIBUTABLE PROVEN RESERVES



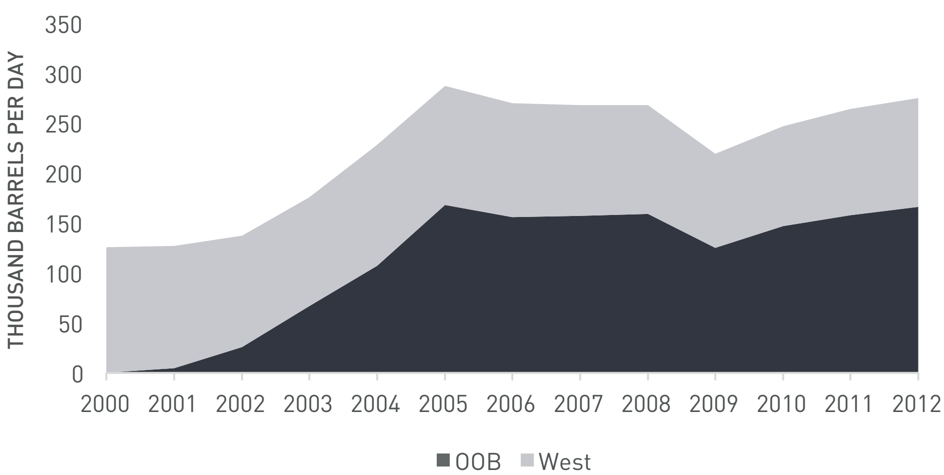
ATTRIBUTABLE SURFACE



ATTRIBUTABLE PRODUCTION BY ASSET



TOTAL PRODUCTION BY DIVISION



Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012), Reporte Especial (Veneconomia, 2006), Wood Mackenzie and CIEA.

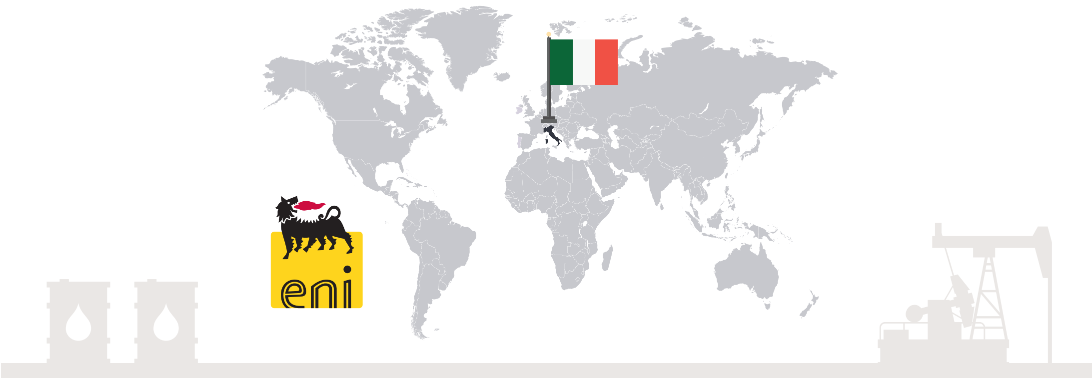
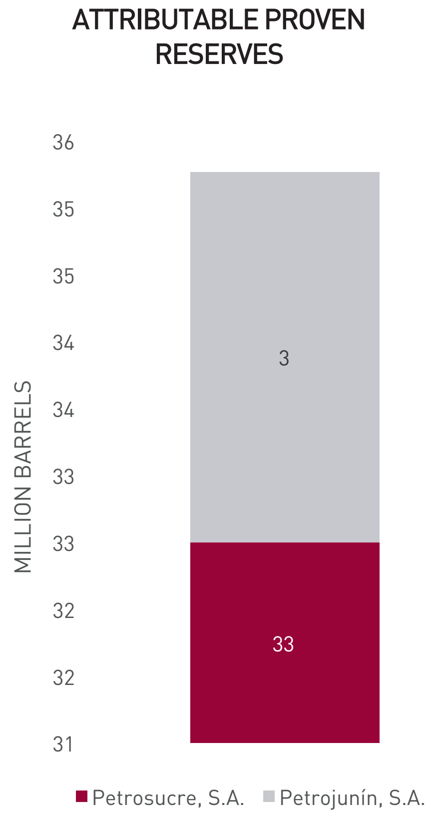


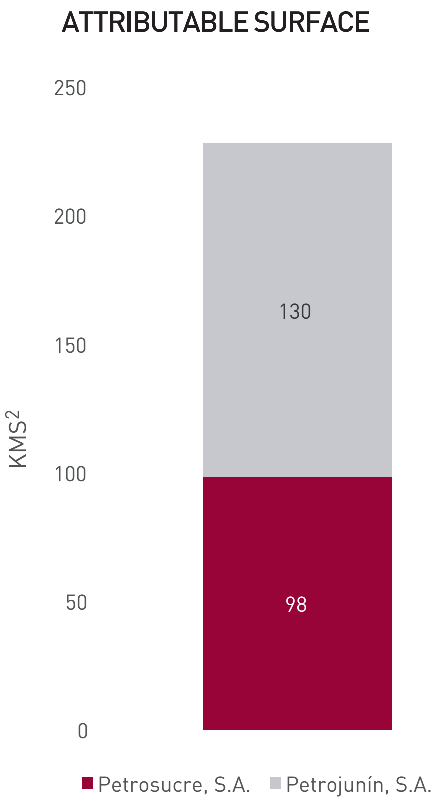
Table 11 ENI: Company profile

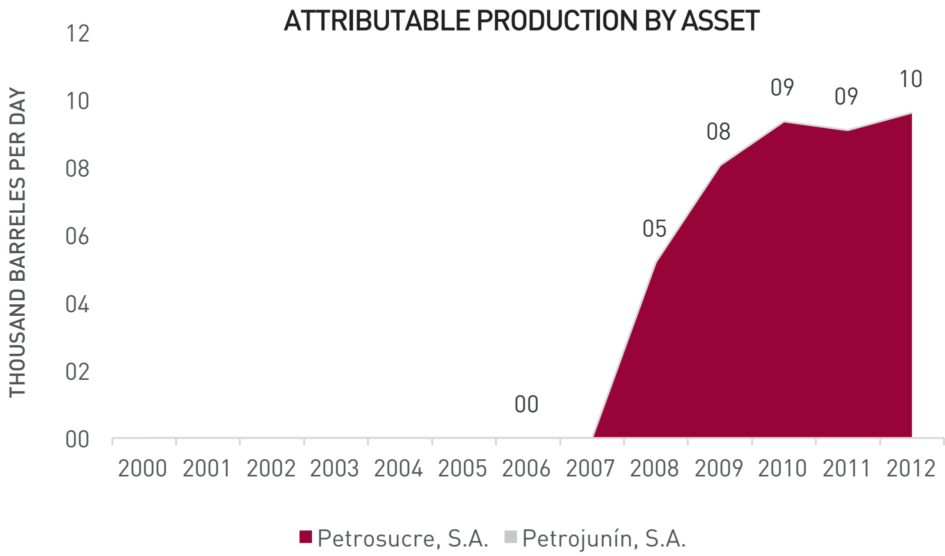
COUNTRY	Italy
FOUNDATION	1953
SHAREHOLDER STRUCTURE	Mixed (30.1% owned by the Ministry of Finance of Italy)
OUTSTANDING SHARES	68%
CHAIN VALUE SEGMENT	Exploration, production and refining
WORLDWIDE	Italy, Algeria, Angola, Congo, Egypt, Ghana, Libya, Mozambique, Nigeria, Norway, Kazakhstan, United Kingdom, United States, Venezuela
TOTAL RESERVES(2014)	3,226 MB
TOTAL PRODUCTION(2014)	1.598 MBOE PER DAY
JV SHARES IN VENEZUELA	• Petrosucre, S.A. • Petrojunín, S.A.

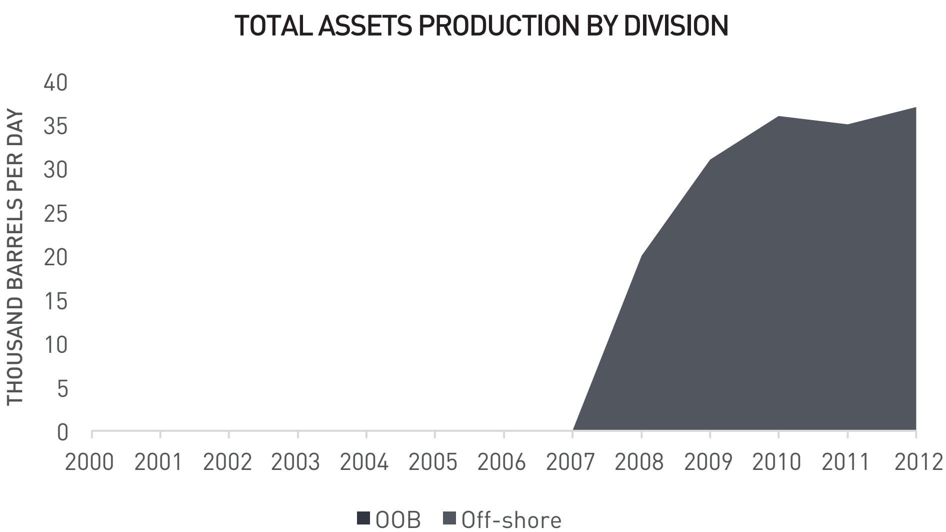
Table 12 ENI: Asset profile

PETROSUCRE, S.A. **COROCORO**	**SHARE:** PDVSA: 74.00% ENI: 26.00% Other partners: N/A. **Offshore Division:** Production (2012): 37 TBD Plateau: 92 TBD (2016)
PETROJUNÍN, S.A.	**SHARE:** PDVSA: 60.00% ENI: 40.00% Other partners: N/A **OOB Division:** Producción (2012): 0 TBD Plateau: 240 TBD (2020)


ATTRIBUTABLE PROVEN RESERVES
36
35
35
34
34
33
33
32
32
31
MILLION BARRELS
3
33
Petrosucre, S.A.
Petrojunín, S.A.


ATTRIBUTABLE SURFACE
250
200
150
100
50
0
KMS2
130
98
Petrosucre, S.A.
Petrojunín, S.A.





Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012) and CIEA.

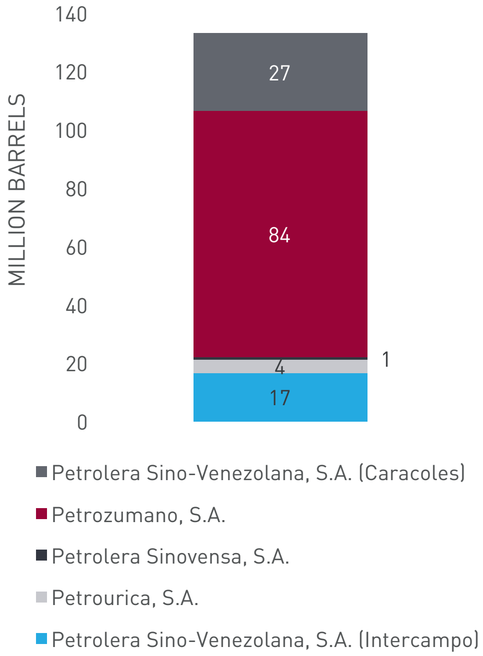
Table 13 CNPC: Company profile

COUNTRY	China
FOUNDATION	1988
SHAREHOLDER STRUCTURE	National Oil Company (NOC)
OUTSTANDING SHARES	13%
CHAIN VALUE SEGMENT	Exploration, Production, Refinancing, Services and oil pipelines.
WORLDWIDE	Canada, Costa Rica, Colombia, Ecuador, Peru, Venezuela, Australia, Japan, Indonesia, Singapore, Thailand, Myanmar, China, Mongolia, Kazakhstan, Uzbekistan, Turkmenistan, Iran, Azerbaijan, Russia, Syria, Iraq, Qatar, Oman, Sudan, South Sudan, Nigeria, Chad, Libya, Algeria, Tunisia, France, United Kingdom
TOTAL RESERVES (2014)	3,700 MB
TOTAL PRODUCTION (2014)	1,392 MBOE PER DAY
JV SHARES IN VENEZUELA	• Petrourica, S.A. • Petrolera Sinovensa, S.A. • Petrozumano, S.A. • Petrolera Sino-Venezolana, S.A.

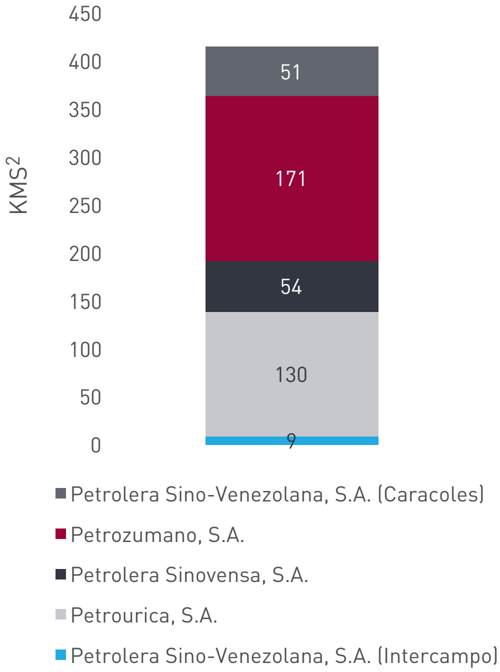
Table 14 CNPC: Asset profile

PETROLERA SINO-VENEZOLANA, S.A. **INTERCAMPO**	**SHARE:** PDVSA: 75.00% CNPC: 25.00% Other partners: N/A. **West Division:** Production (2012): 5 TBD Plateau: 49 TBD (1970)
PETROURICA, S.A. **JUNIN-4**	**SHARE:** PDVSA: 60.00% CNPC: 40.00% Others partners: N/A **OOB Division:** Production (2012): 0 TBD Plateau: N/A
PETROLERA SINOVENSA, S.A. **MPE3 (ORIMULSION)**	**SHARE:** PDVSA: 64.25% CNPC: 35.75% Others partners: N/A **OOB Division:** Production (2012): 117 TBD Plateau: N/A
PETROZUMANO, S.A.	**SHARE:** PDVSA: 60.00% CNPC: 40.00% Others partners: N/A **OOB Division:** Production (2012): 6 TBD Plateau: N/A
PETROLERA SINO-VENEZOLANA, S.A. **CARACOLES**	**SHARE:** PDVSA: 75.00% CNPC: 25.00% Others partners: N/A **OOB Division:** Production (2012): 2 TBD Plateau: 15 TBD (1976)

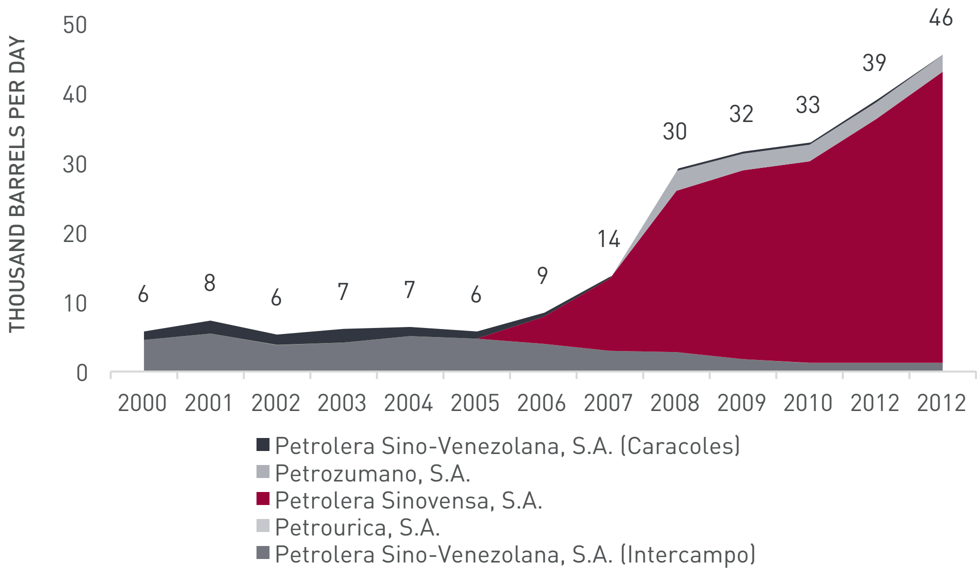
ATTRIBUTABLE PROVEN RESERVES



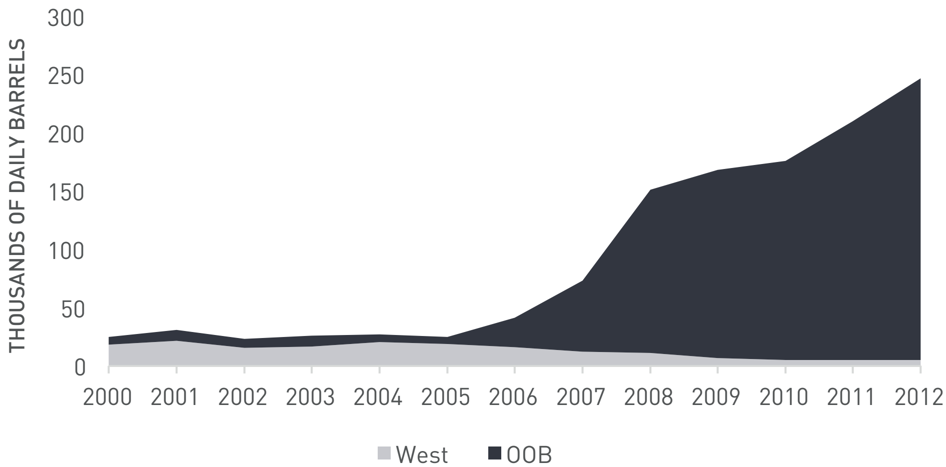
ATTRIBUTABLE SURFACE



ATTRIBUTABLE PRODUCTION BY ASSET



TOTAL PRODUCTION BY DIVISION



Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012), Reporte Especial (Veneconomia, 2006), CNPC website and CIEA.

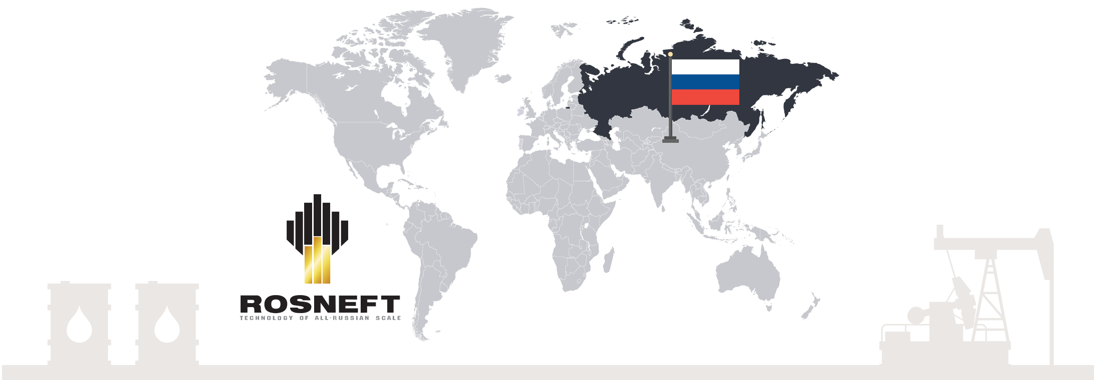


Table 15 Rosneft: company profile

COUNTRY	Russia
FOUNDATION	1993
SHAREHOLDER STRUCTURE	Mixed (69.5% Russian Government, 19.5% British Petroleum)
% OUTSTANDING SHARES	11%
CHAIN VALUE SEGMENT	Exploration, production and refining
WORLDWIDE	Russia, Venezuela, Brazil, United States, Canada, United Arab Emirates, Norway, Algeria, Kazakhstan, Vietnam and Abkhazia
TOTAL RESERVES(2014)	33 MBE
TOTAL PRODUCTION(2014)	4,196 TBD
JV SHARES IN VENEZUELA	• Petroperijá, S.A. • Petromiranda, S.A. • Petromonagas, S.A. • Petrovictoria, S.A.

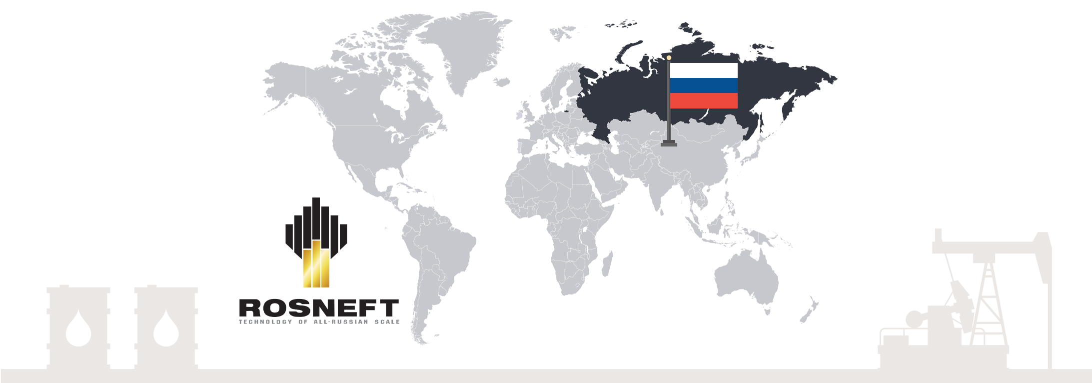
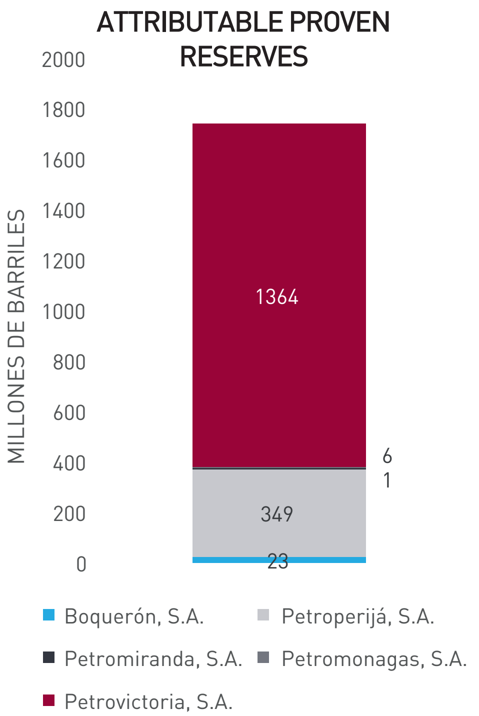
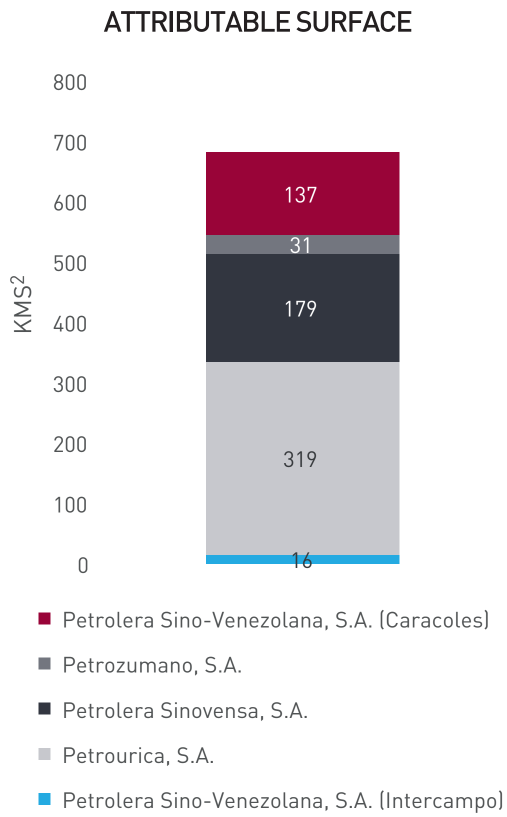


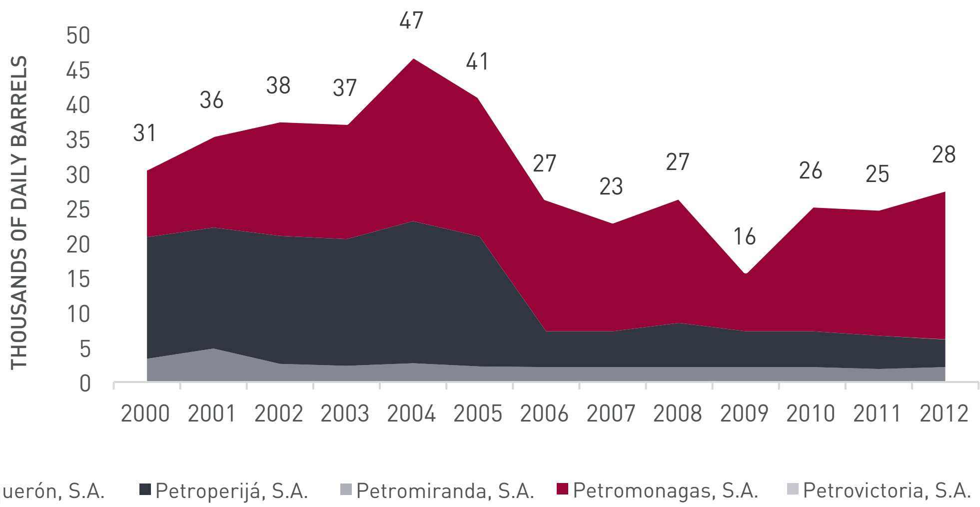
Table 16 Rosneft: Asset profile

BOQUERÓN, S.A.	**SHARE:** PDVSA: 60.00% Rosneft: 26.67% Other partners: OMV (Austria) 13,33% **East Division:** Production (2012): 8 TBD Plateau: 13 TBD (2001)
PETROPERIJÁ, S.A. **URDANETA**	**SHARE:** PDVSA: 60.00% Rosneft: 40.00% Other partners: N/A **West Division:** Production (2012): 10 TBD Plateau: 27 TBD (1996)
PETROMIRANDA, S.A.	**SHARE:** PDVSA: 60.00% Rosneft: 40.00% Other partners: M/A **OOB Division:** Production (2012): 0 TBD Plateau: N/A
PETROMONAGAS, S.A.	**SHARE:** PDVSA: 60.00% Rosneft: 40.00% Other partners: N/A **OOB Division:** Production (2012): 130 TBD Plateau: N/A
PETROVICTORIA, S.A.	**SHARE:** PDVSA: 60.00% Rosneft: 40.00% Other partners: N/A **OOB Division:** Production (2012): 0 TBD Plateau: N/A

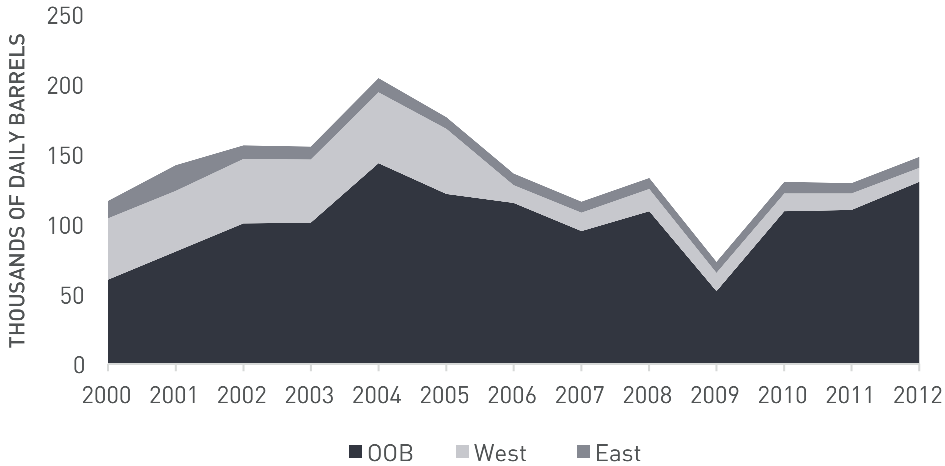

ATTRIBUTABLE PROVEN RESERVES
MILLONES DE BARRILES
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1364
6
1
349
23
Boquerón, S.A.
Petroperijá, S.A.
Petromiranda, S.A.
Petromonagas, S.A.
Petrovictoria, S.A.


ATTRIBUTABLE SURFACE
KMS2
800
700
600
500
400
300
200
100
0
137
31
179
319
16
Petrolera Sino-Venezolana, S.A. (Caracoles)
Petrozumano, S.A.
Petrolera Sinovensa, S.A.
Petrourica, S.A.
Petrolera Sino-Venezolana, S.A. (Intercampo)

ATTRIBUTABLE PRODUCTION BY ASSET



TOTAL PRODUCTION BY DIVISION



Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012) and CIEA.

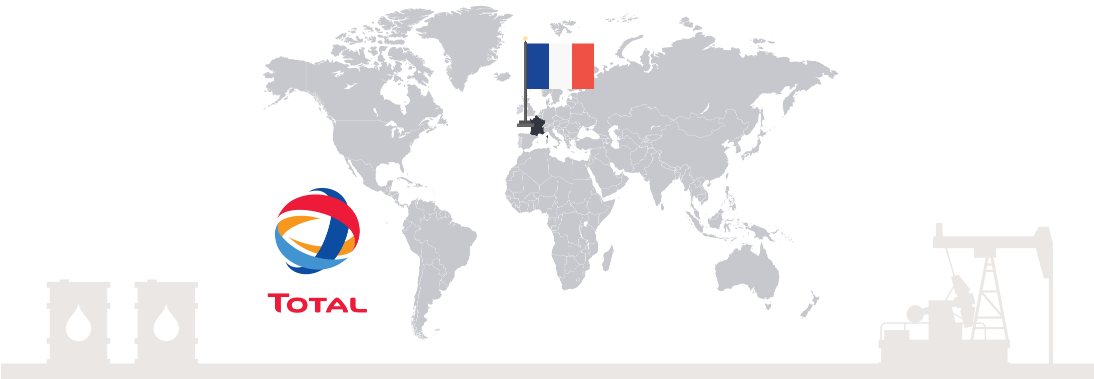


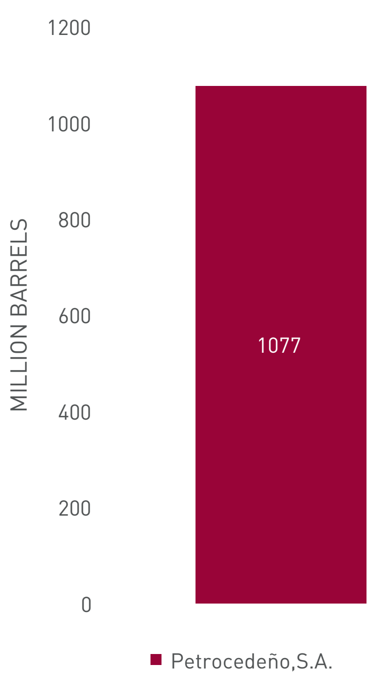
Table 17 Total: Company profile

COUNTRY	France
FOUNDATION	1924
SHAREHOLDER STRUCTURE	International Oil Company
% OUTSTANDING SHARES	93%
CHAIN VALUE SEGMENT	Exploration, production and refining
WORLDWIDE	Algeria, Angola, Gabon, Libya, Nigeria, Congo (Rep.), Canada, United States, Argentina, Bolivia, Colombia, Trinidad and Tobago, Venezuela, Australia, Brunei, China, Indonesia, Myanmar, Thailand, Azerbaijan, Russia, France, Netherlands, Norway, United Kingdom, United Arab Emirates, Iraq, Oman, Qatar, Yemen.
TOTAL RESERVES(2014)	11,523 MBE
TOTAL PRODUCTION(2014)	2,146 MBOE PER DAY
JV SHARES IN VENEZUELA	• Petrocedeño

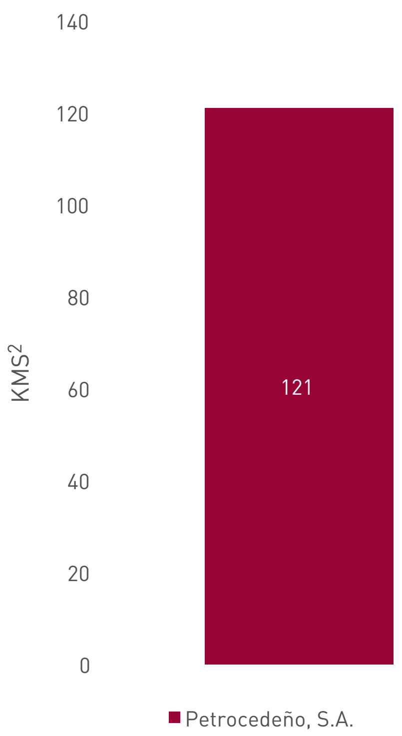
Table 18 Total: Asset profile

PETROCEDEÑO, S.A.	**SHARE:** PDVSA: 60.00% Rosneft: 30.30% Other partners: Statoil (Noruega) 9.70% **OOB Division:** Production (2012): 127 TBD Plateau: 200 TBD (2005)

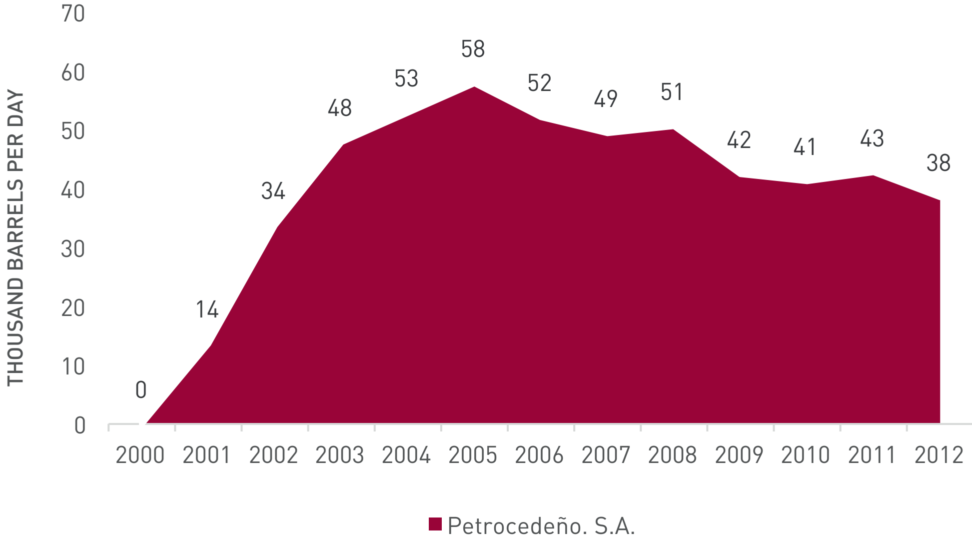
ATTRIBUTABLE PROVEN RESERVES



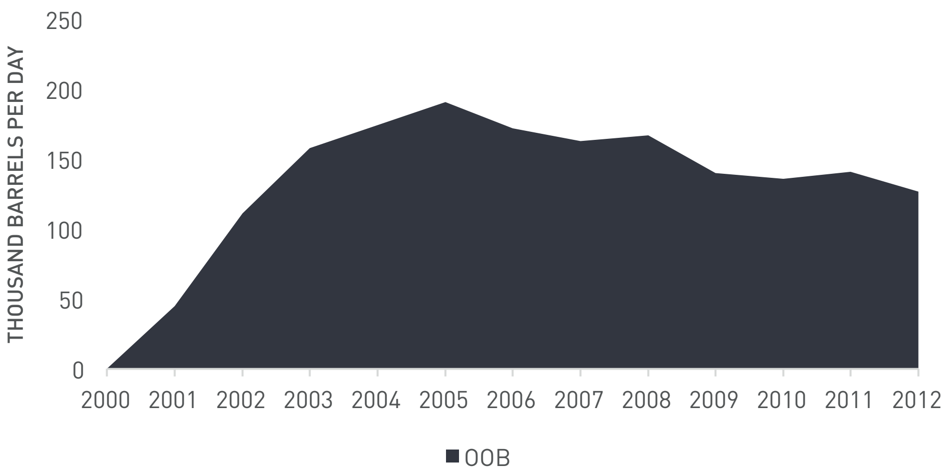
ATTRIBUTABLE SURFACE



ATTRIBUTABLE PRODUCTION BY ASSET



TOTAL ASSETS PRODUCTION BY DIVISION



Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012) and CIEA.

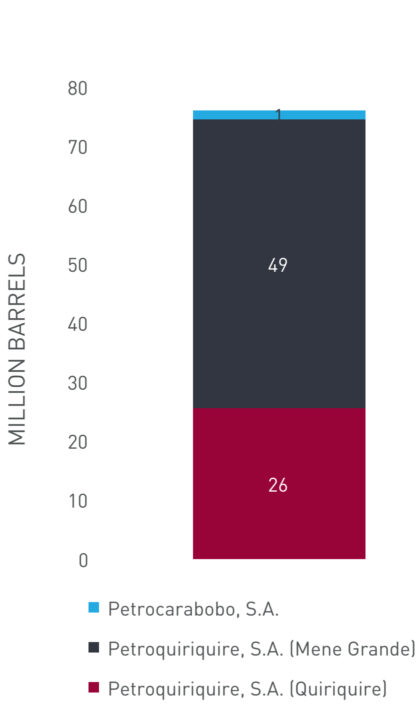
Table 19 Repsol: Company profile

COUNTRY	Spain
FOUNDATION	1987
SHAREHOLDER STRUCTURE	International Oil Company
% OUTSTANDING SHARES	91%
CHAIN VALUE SEGMENT	Exploration, production and refining
WORLDWIDE	Angola, Algeria, Gabon, Libya, Morocco, Namibia, Aruba, Bolivia, Brazil, Canada, Colombia, Ecuador, United States, Guyana, Mexico, Peru, Trinidad and Tobago, Venezuela, China, Indonesia, Iraq, Malaysia, Russia, Singapore, Vietnam, Germany, Bulgaria, Spain, France, Netherlands, Ireland, Italy, Luxembourg, Norway, Portugal, United Kingdom, Romania, Switzerland, Australia, Papua New Guinea
TOTAL RESERVES(2014)	1,460 MBE
TOTAL PRODUCTION (2014)	700 MBOE PER DAY
JV SHARES IN VENEZUELA	• Petroquiriquire, S.A. (Quiriquire) • Petroquiriquire, S.A. (Mene Grande) • Petrocarabobo, S.A.

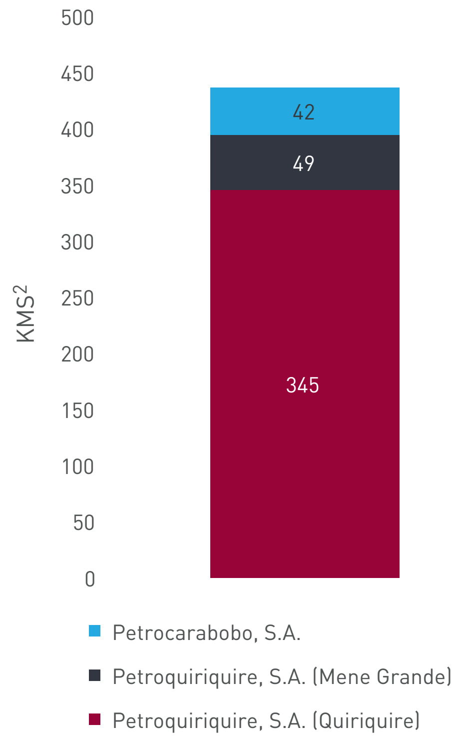
Table 20 Repsol: Asset profile

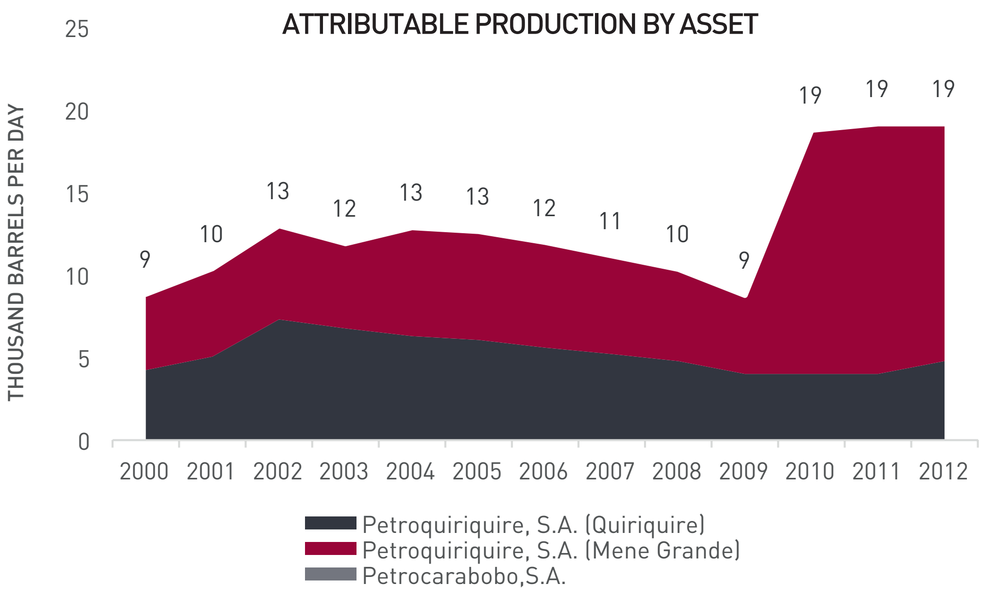
PETROQUIRIQUIRE, S.A. (QUIRIQUIRE)	**SHARE:** PDVSA: 60.00% / Repsol: 40.00% / Other partners: N/A. **East Division:** Production (2012): 12 TBD / Plateau: 60 TBD (2019)
PETROQUIRIQUIRE, S.A. (MENE GRANDE)	**SHARE:** PDVSA: 60.00% / Repsol: 40.00% / Other partners: N/A. **West Division:** Production (2012): 36 TBD / Plateau: N/A
PETROCARABOBO, S.A.	**SHARE:** PDVSA: 60.00% / Repsol: 11.00% **OOB Division:** Production (2012): 0 TBD / Plateau: 360 TBD (2021)

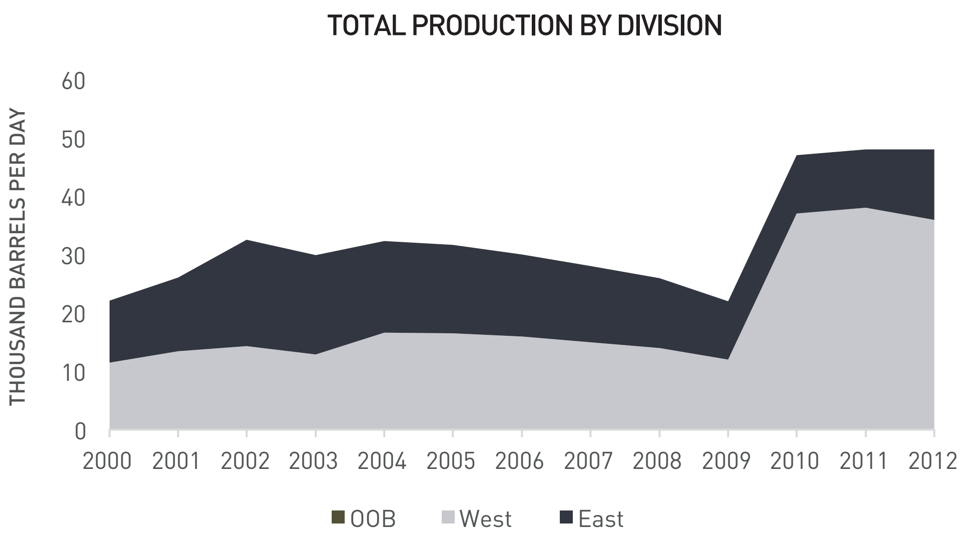
ATTRIBUTABLE PROVEN RESERVES



ATTRIBUTABLE SURFACE







Sources: Annual Management Report 2014 (PDVSA, 2015), PODE (MENPET, 2012), Reporte Especial (Veneconomia, 2006) and CIEA

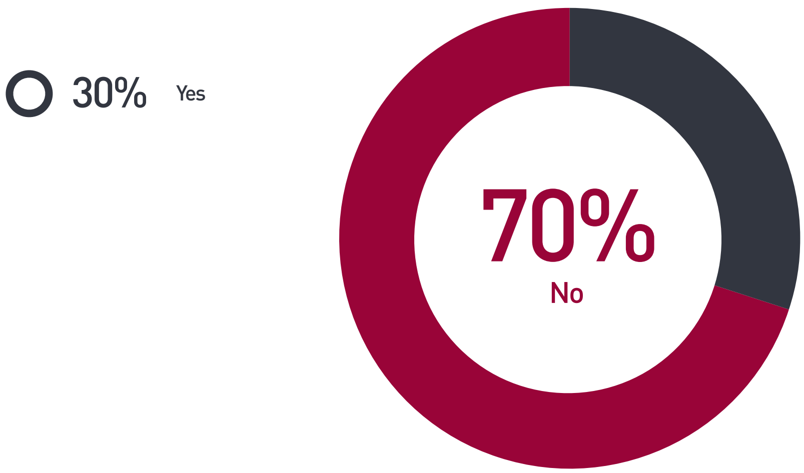
EXPERT'S SURVEY: OPPORTUNITIES AND CHALLENGES IN THE ORINOCO OIL BELT (OOB)

Between October 2015 and February 2016, the International Center on Energy and the Environment surveyed managers of Joint Ventures and partner companies with operations in the Orinoco Oil Belt area. This initial approach aimed to capture different valuations from operators in the zone about various factors which could constitute opportunities for activity expansion, as well as current challenges when executing their operations.

The poll's questions were selected through a series of discussions with senior analysts and consultants in the oil and gas industry, which have examined the OOB situation recently.

During the considered period, 10 managers were interviewed and the next pages show the results according to their answers. These results do not constitute any description of all of the relevant opinions nor a generalization of any type.

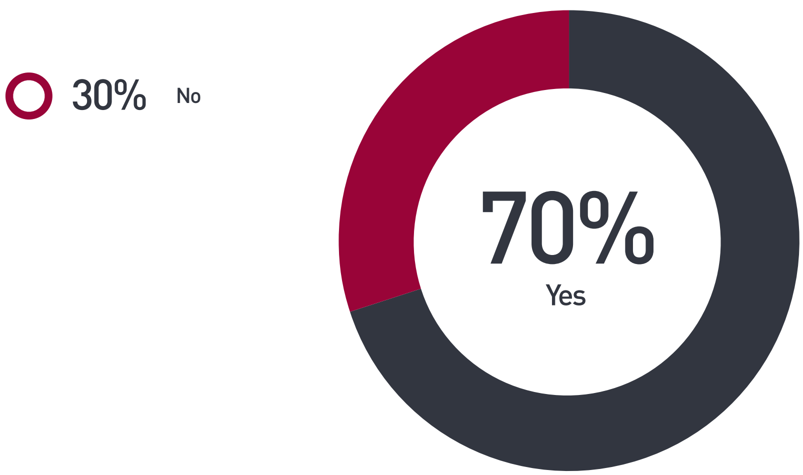
Figure 63 Has the JV in which you work an upgrader already operating?



Source: CIEA

Most managers consulted do not belong to a company with an extra-heavy crude oil upgrader facility, which means that the business is mainly based on diluted crude oil blending. The presence of an upgrader is determinant to the currency composition of CAPEX and OPEX, as the foreign currency availability and the exchange system have different significance in cost terms for each operating scheme. No-upgrader companies have a bigger share in foreign currency expenses due to diluent import needs, upgrader JVs have probably more expenses in national currency. The consequence is that for the first group foreign currency availability is key, and for the other the effective exchange rate applicable to oil exports could be more relevant.

Figure 64 Has the JV in which you work access to SIMADI exchange rate?



Fuente: CIEA

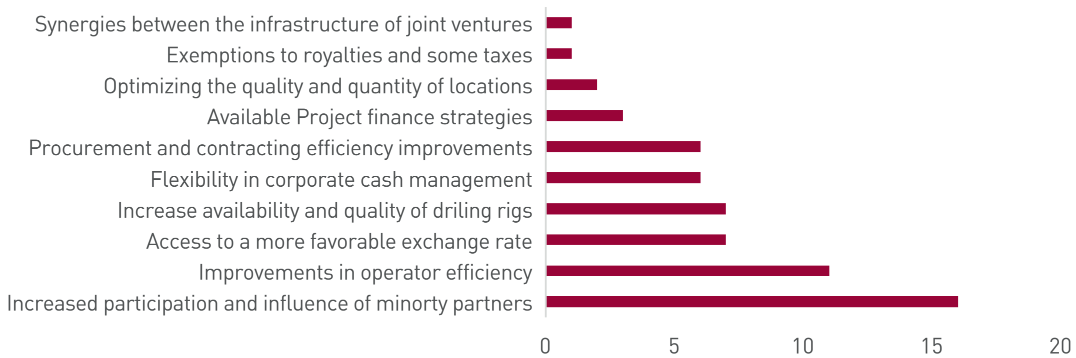
The majority of surveyed managers said that they have actual access to the SIMADI exchange rate, which was the higher existing exchange rate in the polling period. SIMADI averaged 200 VEF per USD, which means that this companies had less expenses in foreign currency to cover its local currency costs. Meanwhile, companies with no access to this system have higher expenses expressed in a 12 VEF/USD exchange rate.

OPPORTUNITIES

To account on the elements considered as opportunities to the group of polled experts, they were asked to classify by relevance the three main factors –from a group previously selected– which they considered as opportunities according to their criteria. The highest ranked factor received a score of three, followed by the second in importance with a score of two and one for the less ranked. Unconsidered factors received a score of zero. Final factors were selected by adding all of the scores in each factor by person.

Results show that the most remarkable feature identified as an opportunity in the OOB is to give more participation to the minority partners in the JVs with PDVSA. At the same time, improvements in operating efficiency, the access to more competitive exchange rates and the increase in the number and quality of suppliers had an important valuation to the experts.

Figure 65 Opportunities in the Orinoco Oil Belt



Source: CIEA.

CHALLENGES

By repeating the previous method, a last question was made to the group of managers regarding the main current challenges when operating in the OOB. High investment needs and the distortions associated to the exchange rate system were the most valued issues, followed by the lack of financial independence.

Figure 66 Challenges in the Orinoco Oil Belt

Source: IESA-CIEA

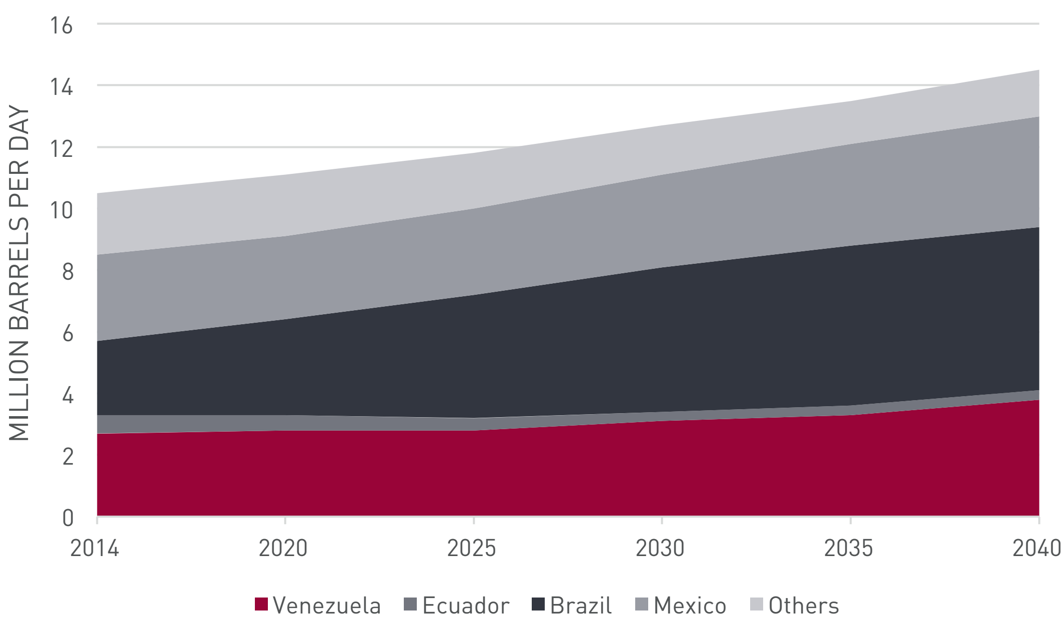
Even when the conclusions raised do not allow to make a generalizable analysis to the whole OOB current landscape, given the limitations of the sample, this survey can represent an initial guideline for further research. The OOB represents a highly relevant asset for the Venezuelan oil industry development and there exists a need for a more clear vision of its prospects in the short, medium and long term.

PROJECTIONS

OIL MARKET PROJECTIONS

Oil and gas market projections as exposed in this section were taken from the "New Policies Scenario" of the International Energy Agency (IEA). This scenario –central to the World Energy Outlook 2015– takes into account the policies and measures on environmental issues that will probably impact the global energy markets in the coming decades. These policies were assumed in mid-2015 and reaffirmed in the XXI Framework Convention on Climate Change, which took place in December in Paris.

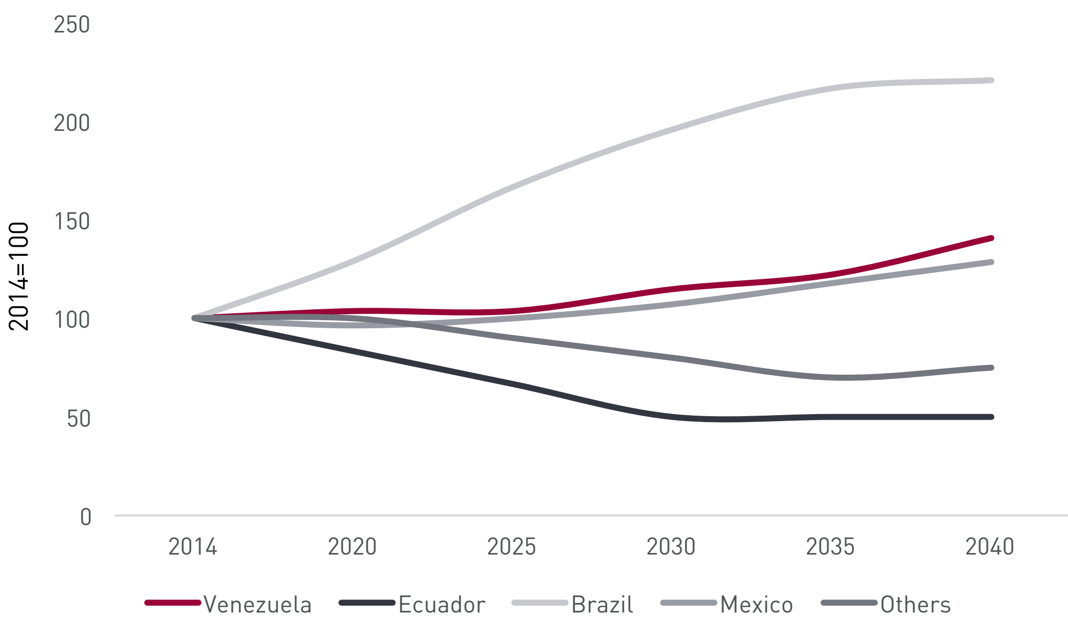
Figure 67 Crude Oil Projected Production, Latin America (2020-2040)



Source: World Energy Outlook 2015 (IEA, 2015).

In the new policies scenario, crude oil production in Latin America is expected to grow over 14.7 tbd in 2040. This scenario estimates a growth in production for Brazil from 2.4 tbd in 2014, to 3.1 tbd in 2020, 4.0 in 2025, 4.7 in 2030, and a final decrease from 5.3 to 5.2 tbd in 2035-2040. Total production growth for the continent is estimated in 4 tbd from 2014, a reduction of 400 tbd since the last projections. Incremental production is expected to come from: Brazil (3.6 bcm), Venezuela (1.2 bcm) and Mexico (0.4 bcm). For Ecuador and other countries, the IEA projects a decline in production of 0.3 and 0.5 tbd, respectively.

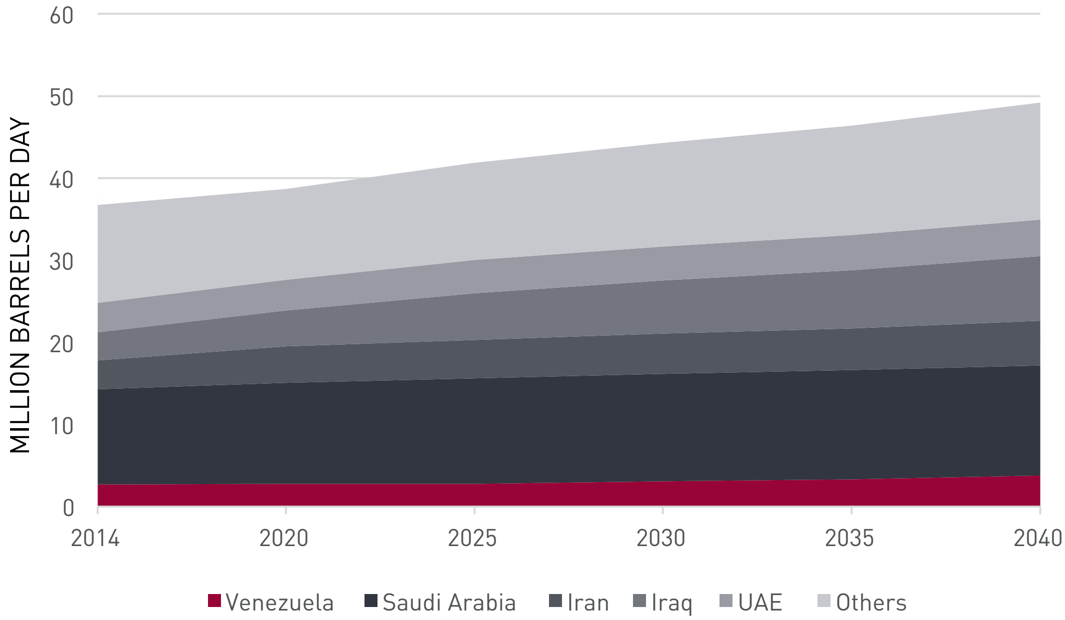
Figure 68 Growth projections for crude oil production, South America (2014=100)



Source: World Energy Outlook 2015 (IEA, 2015) and CIEA.

Latin American countries particular share in production growth is clear when forecasts are based in 2014. Production growth rate is expected to decline for Brazil and increase for Venezuela from 2035. Total production growth to 2040 rose to 121% for Brazil, 41% for Venezuela and 29% for Mexico. Ecuador decline in production is projected to be close to 50% and 25% for the rest of the region.

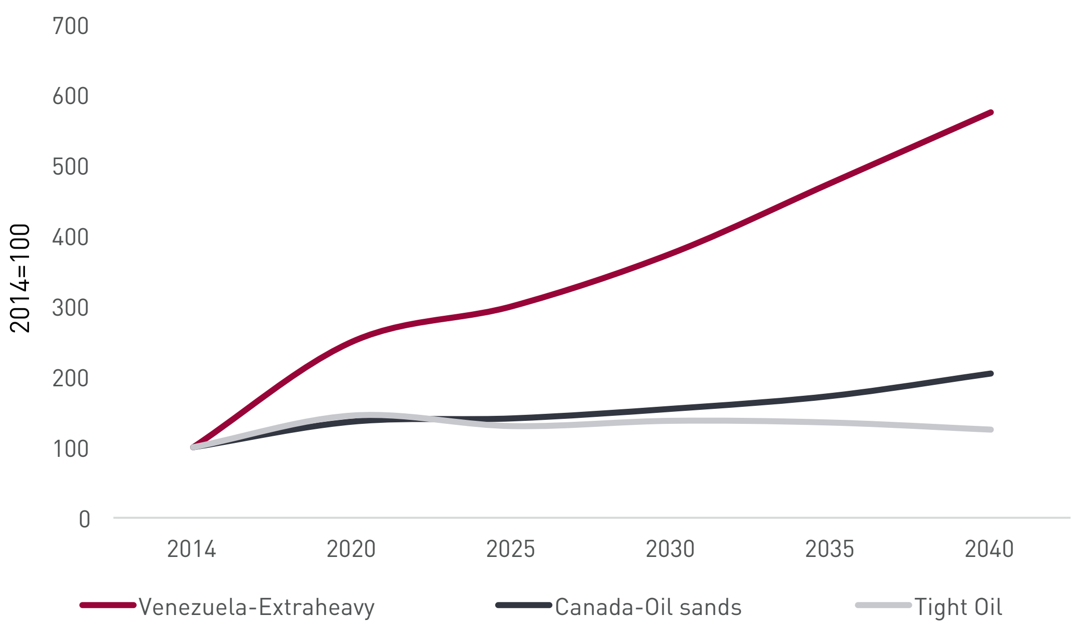
Figure 69 Projected oil production, OPEC Countries



Source: World Energy Outlook 2015 (IEA, 2015).

The IEA outlook shows an increase in OPEC member countries production of 12.5 tbd until 2040, from current 36.7 tbd to 42.2 tbd. Most of this growth is projected to come from Iraq, which is expected to have a strong return to the market over the long term by adding 4.5 tbd to its 2014 production figure. The next supporters for OPEC expected production growth are Iran (1.9 tbd), Saudi Arabia (1.8 tbd) and Venezuela (1.1 tbd).

Figure 70 Production growth projections, unconventional crudes

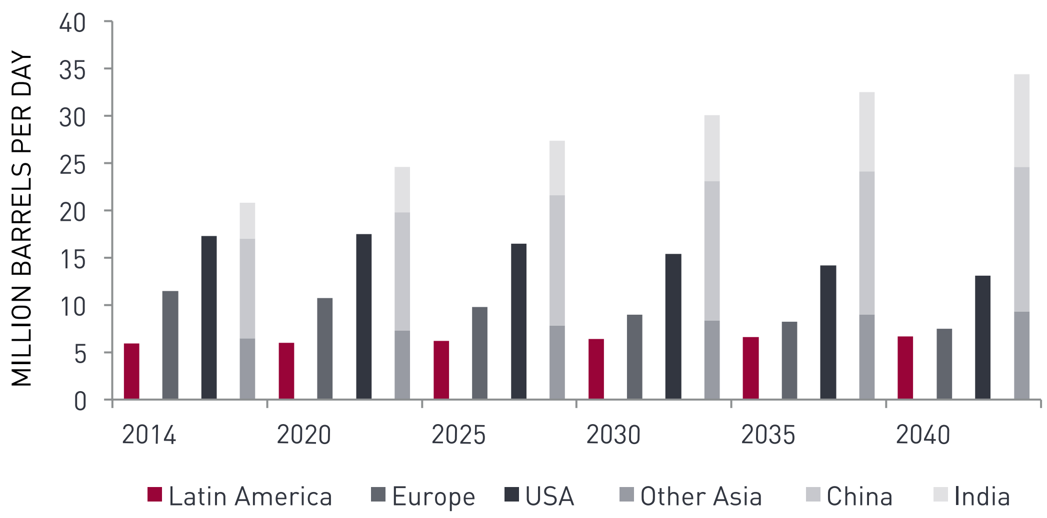


Source: World Energy Outlook 2015 (IEA, 2015) and CIEA.

Over the long run, most of unconventional crude oil production growth will be from Venezuela, according to the IEA. The agency expects that the projects from the Orinoco Oil Belt will generate a five-fold increase in extra-heavy crudes in 2040, exceeding by far the growth prospects for Canadian oil sands which is expected to be 104%. Besides, tight oil loses relevance by 2020 when its production is expected to reach a peak, gaining only 25% of additional production in 2040 as compared to 2014.

OIL CONSUMPTION PROJECTIONS

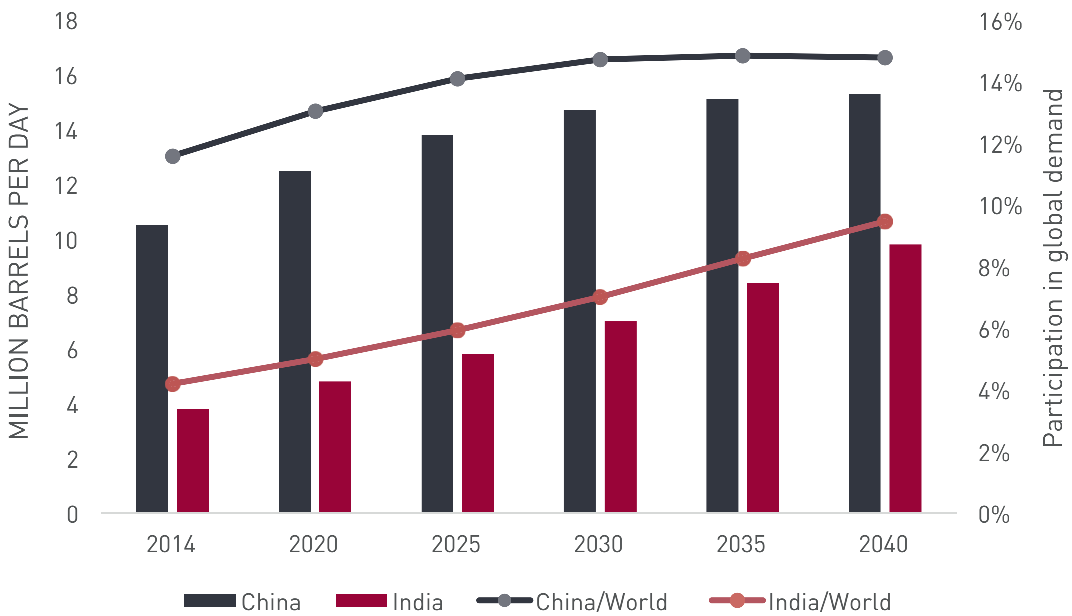
Figure 71 Oil Consumption Projections



Source: World Energy Outlook 2015 (IEA, 2015)

The IEA anticipates an important increase in crude oil consumption for India, which is projected to be of 6 tbd between 2014 and 2040. Indian subcontinent consumption level will change from 3.8 tbd to 9.8 tbd, becoming the engine growth of fuel demand in that period. Meanwhile, China's consumption is expected to grow by 4.8 tbd, from current 10.5 tbd to 15.3 tbd in 2040. Globally, the agency foresees that consumption will probably grow 12.9 tbd in 2014-2040, reaching 103.5 tbd by the end of the period. After India and China expected growth, follows in importance those of other Asian countries (2.8 tbd) and Latin America (0.8 tbd). Other regions will see a drop in consumption in this scenario, in which demand is projected to be near 4 tbd lower for the United States and Europe, in which the IEA estimates the consumption peak has been reached.

Figure 72 Oil demand projections

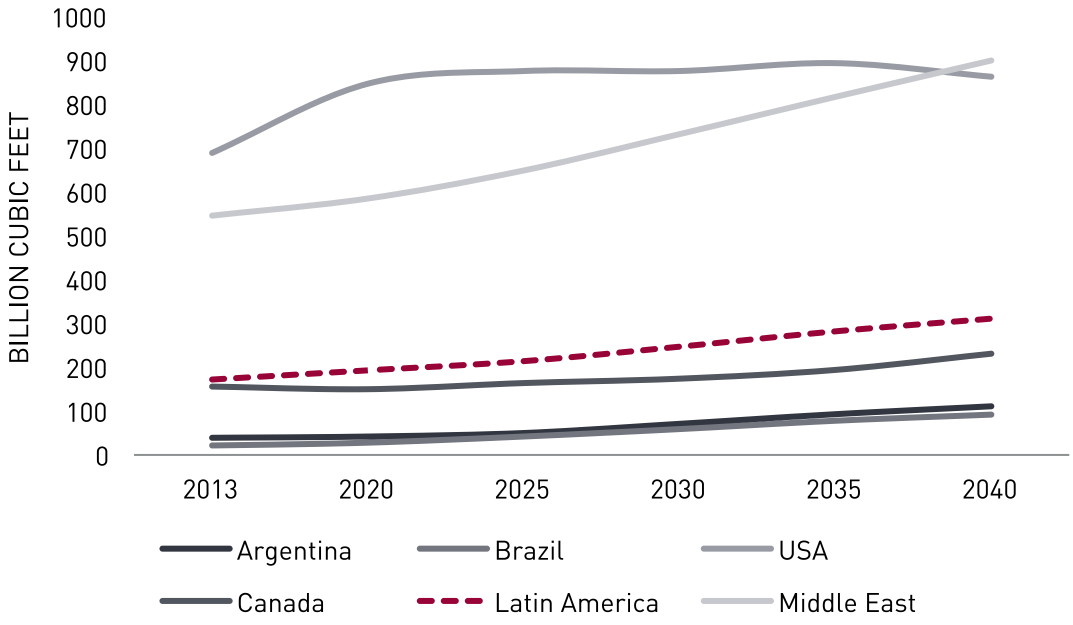


Source: World Energy Outlook 2015 (IEA, 2015).

The IEA foresees that, into the new policies scenario, most of global crude oil demand will tend to be less explained by China and in more proportion by India. In 2014-2040, the last is expected to get 10% of global consumption by 2040, which means a 6% increase from current levels. On the other hand, China's share will be 15%, growing 3% in 2014-2040.

GAS MARKET PROJECTIONS

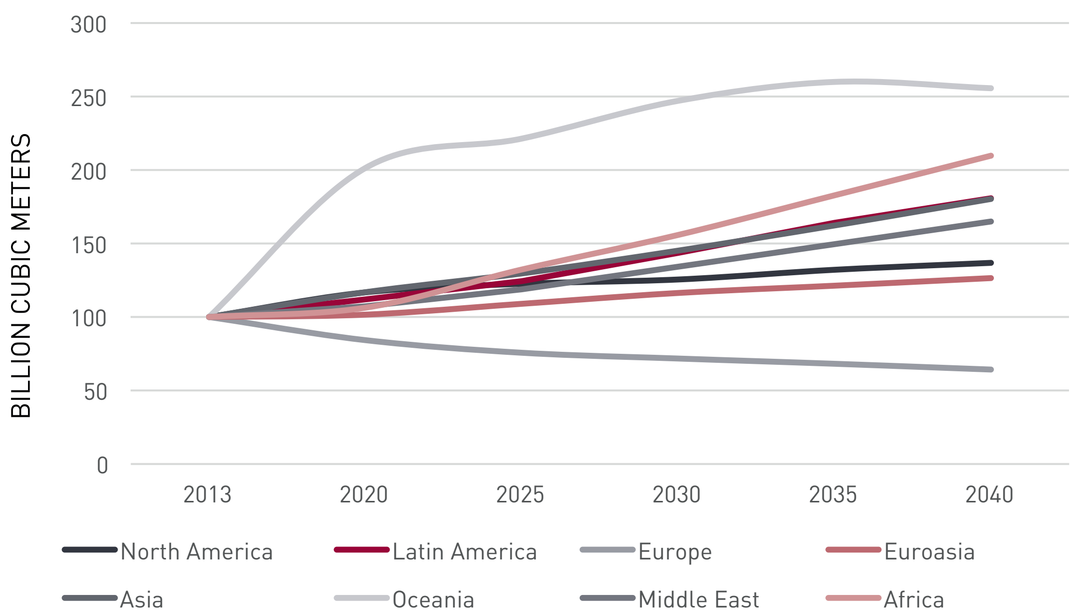
Figure 73 Natural Gas Production Projection, selected regions and countries (2020-2040)



Source: World Energy Outlook 2015 (IEA, 2015).

The IEA expects Latin American countries gas production to expand in 139 bcm by 2040. During 2013 the region produced near 5% of world total, while projections expect this ratio to rise over 6% in 2040. Argentina and Brazil are the leaders in this production growth forecast, with increases of 72 bcm and 71 bcm, respectively. By the end of the period, these countries will be responsible for 65% of Latin America total production. Meanwhile, Middle East production will grow enough to catch up the United States production in 2035-2040, which in turn will diminish after reaching a peak in 2020, according to this scenario.

Figure 74 Projected production growth by continent (2012=100)

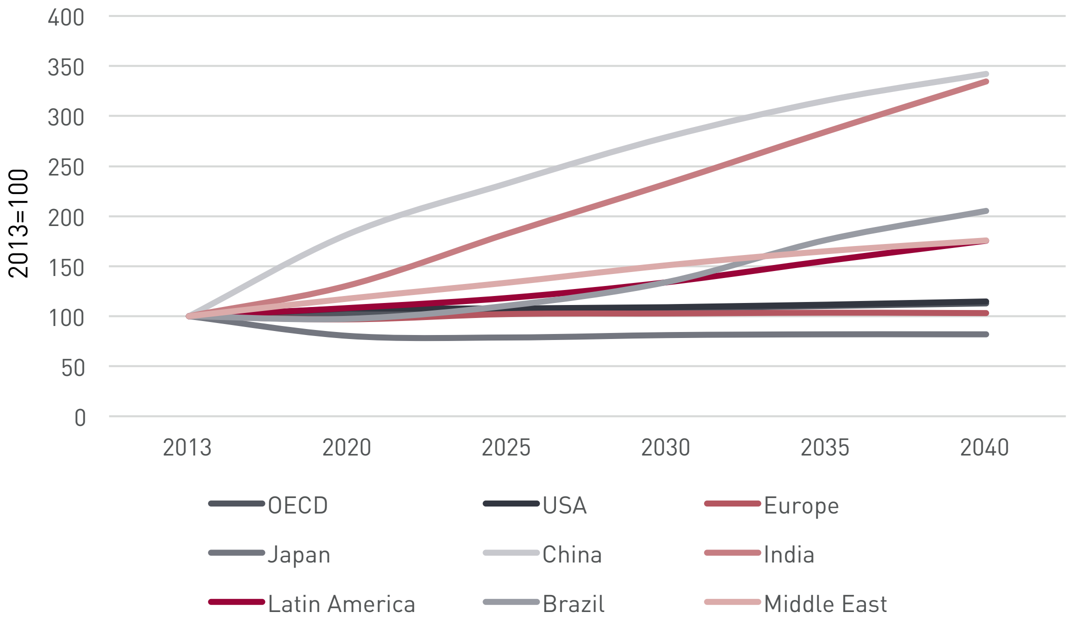


Source: World Energy Outlook 2015 (IEA, 2015).

Most of global production growth until 2020 will come from Oceania, thanks to important reservoir discoveries in east and west Australia which will increase threefold this continent's production, according to the IEA. On the other hand, IEA's projections suggests that European OECD countries will lose global market share given a 24% decreased in its production to 2040.

GAS CONSUMPTION PROJECTIONS

Figure 75 Projected gas consumption growth (2013=100)



Source: World Energy Outlook 2015 (IEA, 2015).

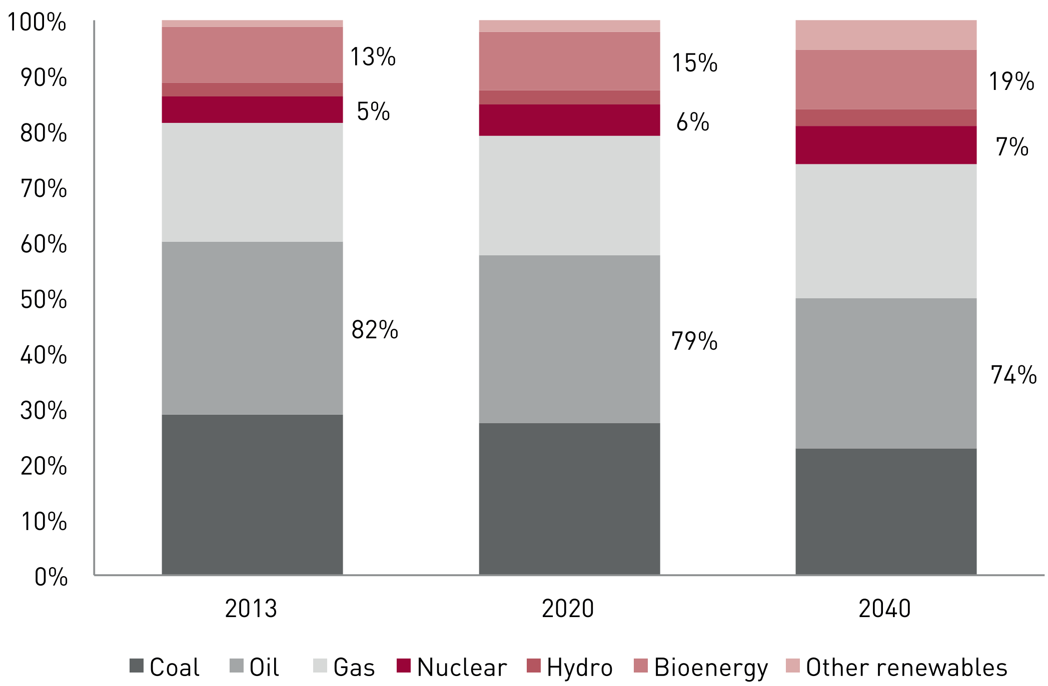
Gas demand will rise by 47% according to the New Policies scenario. This increase has fundamentals in particular characteristics of natural gas in terms of price and reduced environmental footprint –as compared to crude oil- which make it a potential transition fuel to renewable energy. Asia, particularly China and India, could lead this consumption growth with an expected increase of 242% and 234%, respectively.

ENERGY CONSUMPTION PROJECTIONS

In the context of the global energy mix, the New Policies scenario shows a changing future for the oil and gas industry. The movement into substitution of fossil fuel for renewable and clean energy sources, as well as the incentives towards efficiency in energy use, outline a reduction in hydrocarbons as energy source by 2040.

Total energy consumption is expected to grow by 32% in 2013-2040. As compared to 2013, fossil fuel demand will increase by 18% (2% for carbon, 12% for oil and 46% for natural gas). Nuclear energy demand is expected to grow by 86% and for renewables the figure rose to 80% (63% for hydro, 36% for bioenergy and 482% for other).

Figure 76 New Policies Scenario: projected share of fuels in the energy mix (2020-2040)



Source: World Energy Outlook 2015 (IEA, 2015).

The New Policies scenario considers a drop of 72% of fossil fuels share into the energy mix in 2040. Even when coal, oil and gas will endure as the main energy sources, they will be the only group –not individually– whose share will be reduced. Nonetheless, natural gas will increase its share by 3%, as nuclear is expected to grow 2% and renewables as hydro and other will grow their own 1% and 4%, respectively. The IEA does not expect bioenergy demand –which includes new technologies and traditional biomass use- to change.

The New Policies scenario highlights the importance of renewables, nuclear and natural gas in the future energy mix. This fuel sources are relevant to the movement over less polluting energy consumption patterns, which is the direction taken by the recent climate change mitigation policies globally. It is also important the less accelerated growth in total energy consumption due to the expected energy efficiency changes. Finally, natural gas industry generates an opportunity window for traditional hydrocarbon producers, being the best adapted fossil fuel to the new patterns.

BOX /6

THE COP 21 AND VENEZUELA'S OIL FUTURE

– BY MARÍA ALEJANDRA DE FRANCESCO & IGOR HERNÁNDEZ –

The dialogue on climate change has been on the rise since 1992, reaching a critical point in December 2015 when the Conferences of Parties was celebrated. Over 38 thousand delegates attended to discuss a common topic: how can economic growth levels can be sustained or increased without causing irredeemable damages to the Earth and its inhabitants?

Beyond the public policy actions contained into the Paris agreement for each country in particular, it is evident that the world leaders are coordinating big efforts in order to achieve a future in which the global economy growth and development can be decoupled from carbon emissions. It is a key issue for the Venezuelan oil industry to understand the specific vulnerabilities in the context of these new policies. For that reason, we will examine general features of the agreement, their effects into fossil fuels use and their implications for the national oil sector.

COP 21 and the Paris Agreement

The main purpose of the Paris Agreement is to reach a peak in CO^2 emissions as fast as possible. The underlying goal consists in keeping average global temperatures below 2°C –as compared to pre-industrial levels– until 2100. Besides, the countries who have signed the agreement made a commitment to limit temperatures growth to less than 1.5°C. In order to reach this objective, each nation established a series of actions called "Intended Nationally Determined Contributions". INDCs are tools to design environmental policies according to their own capacities and needs.

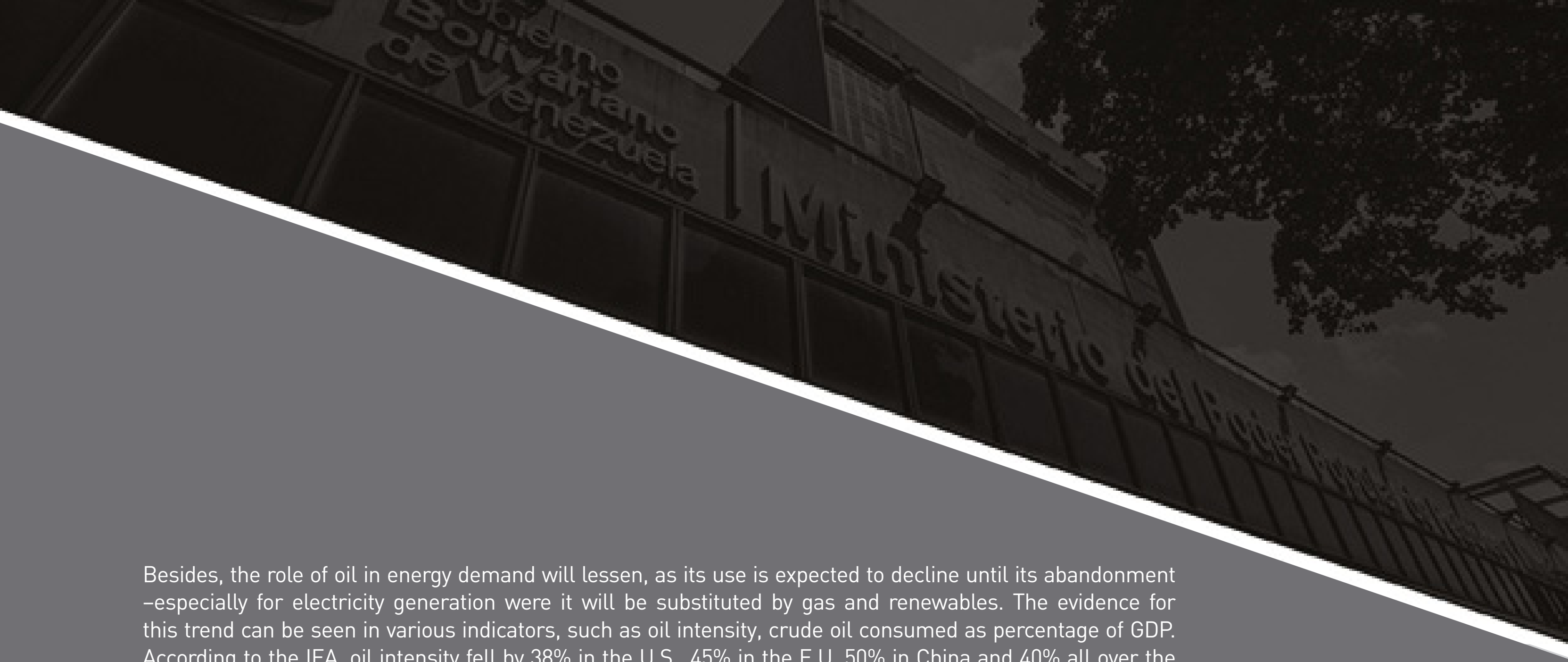
The agreement brought together developed and developing countries under the motto "common but differentiated responsibilities". Financial matters capture this slogan, as developed countries must send 100 billion USD per year for 2020 and the necessary technical assistance for the most affected countries by climate change. The consequences of the policies are associated to possible scenarios of energy demand path in the coming years, but uncertainty about their timing and extent still persists. Nonetheless, the implications described below are happening and the risks are present.

Implications for fossil fuels usage

Between 1990 and 2013, according to the International Energy Agency, primary energy demand grew by 55%. In the future, this rate is expected to fall. There are elements in the short term that impact negatively this rate, such as economic growth slowdown. However, deeper changes related to energy efficiency are expected to come. Therefore, IEA energy demand scenarios anticipate a growth rate from 12%, related to strict carbon emissions policies scenarios, to a 45% if current economic and energy policies remain unchanged.

Energy efficiency policies are positioned as effective tools to reach the peak emissions goal. These policies are having effects already: global energy consumption has expanded in 0.7% in 2014, as compared to an alternative estimate of 2.1% without energy efficiency improvements.

The replacement of thermoelectric plants for equipment that generates less carbon dioxide, the placement of regulations for the transport sector, the alterations in infrastructure and refurbishment of buildings to achieve a lower demand on heating and the future breakthroughs in storage and transportation of energy are elements which suggest that, even considering an scenario of prolongued growth, the increase inenergy demand will be smaller each time.



Besides, the role of oil in energy demand will lessen, as its use is expected to decline until its abandonment –especially for electricity generation were it will be substituted by gas and renewables. The evidence for this trend can be seen in various indicators, such as oil intensity, crude oil consumed as percentage of GDP. According to the IEA, oil intensity fell by 38% in the U.S., 45% in the E.U, 50% in China and 40% all over the world. Nevertheless, coal and oil reduced share into the energy matrix does not mean an immediate substitution to renewable sources.

Although the COP 21 2°C scenario expects a relevant share of renewables in the energy mix, there are at least two elements to be considered by relevant players. First of all, the development of renewables sources require large investments. The IEA projects 260 USD billion in investments in renewables per year globally, if current agreement policies are implemented. Thus, more limited emissions will require over 400 USD billion per year, which in the short term can be affected by current hydrocarbon prices.

Moreover, it is necessary to face barriers in the development of projects related to renewable energies. For instance, studies in this regard show that many projects do not advance from research phase to commercial launch6. Causes are related to uncertainty regarding potential value of projects and related risks in early stages, hence private financial funding is limited. Furthermore, public financing can dismiss projects with high prospects in the long term but high costs in the short term. All this makes the new energies development process very uncertain.

Risks and opportunities

It is relevant to consider that, even if INDCs agreements are implemented, the United Nations estimates that associated carbon dioxide emissions would be consistent with a temperature growth near 3.7°C. This is a common forecast for diverse organizations that have analyzed the impact of December's commitments[1].
The extent of transformations expected under these scenarios has yet to be determined. But implications for the energy sector can shed light over changes to come for the planet. Some effects in the sector are linked to potential fuel supply and electricity irruptions due to sudden meteorological changes. Katrina hurricane and New Orleans's blackouts are an example.

On the other hand, water availability can harm many routine processes in the oil industry. Shale oil and oil sands production is water-intensive and can be severely affected by its scarcity. Besides, water is used in the cooling of thermoelectric units and is essential to produce biofuels. Other consequences include off-shore associated risks and unexpected temperature changes that can increase electricity utilization for refrigeration or diminished heating fuel demand in winter.

The magnitude of the threat means that changes have to be more profound in order to mitigate climate change, therefore the shift in energy demand could happen sooner than later. The challenge for companies in this sector is to maintain competitiveness. For example, 18% of potential emissions reductions could come through efficiency gains in the oil and gas industry[2]. Surely, to achieve a major reduction in emissions requires development of carbon capture and storage technologies, or the implementation of enhanced oil recovery technologies through captured CO_2 injection[3].

What does all this mean for Venezuela? It seems that fossil fuels will maintain their relevance in meeting energy demand in the coming years. Even so, unavoidable risks and uncertainty can force to rethink scenarios unexpectedly. Venezuela's relevant position in the energy landscape compels the country to anticipate future

energy requirements, in order to traduce our resource endowment into a source of competitiveness for the national oil and gas industry. Venezuelan oil export basket has changed during the last decades, as a consequence of reduced lighter crudes production and an increasing heavy and extra-heavy crudes and products like fuel oil. This migration reflects a serious environmental problem: heavy oil production is an energy intensive process[4]. This means that the industry's associated emissions have been growing.

In this context, it is necessary to consider which could be potential markets in the future. Countries like China expect to reduce its coal consumption in thermoelectric generation in the coming 20 years, for which is reasonable to think that oil products consumption could be an attractive substitute. Meanwhile, as the United States has reduced crude oil imports, the U.S. Energy Information Administration expects an increase in inputs to produce diesel and a high share of heavy and extra-heavy crudes processing capacity remains in this country. Venezuelan crudes and products can be placed in these markets.

Taking into account these facts, costs and competitiveness of Venezuelan crudes in international oil markets becomes even more relevant. Considering the size of extra-heavy oil existing reserves in Venezuela, the question has not been trivial. In addition, the historical role of oil in the Venezuelan industry has meant to pay less attention to the development of natural gas as a competitiveness source for the sector. Outlined scenarios ask for opportunities to create value through new business models which allow to identify appropriately existent resources, as well as to find opportunities in natural gas use for energy and industry purposes (e.g. petrochemicals). This development should also consider environmental issues imposed by the planet natural constraints.

Many key players world-wide have captured these trends and are preparing themselves as a consequence: recently, Saudi Arabia plans to raise a sovereign fund valued in USD 2 trillion, as part of a strategy aimed to diversify the economy and reduce their hydrocarbon dependence. In the case of Venezuela, some concrete questions arise: Has Venezuelan industry a clear approach to face climate policy scenarios? How can be assured future income flows for an industry which represents over 96% of total exports? This questions on economic diversification have remained under discussion for most of oil exploitation history in Venezuela. Still, there is huge uncertainty in this regard.

Climate change challenges lead us to think in competitiveness, irrespective to the sectors being developed. For energy sector, this question involves multiple players, including private and public sector as well as non-for-profit organizations, academia and think tanks. Collaborative work on R&D, human capital qualification and other matters, would allow to develop new products to meet energy demand by using existing geological resources and allow to create employment and added value to the economy.
Venezuela cannot –and should not- be isolated from this debate, given the need to find the proper political, institutional and social setting to support competitive sectors development. It also implies to take into account the risks coming and to set an agenda in order to prepare for the future, without deferment. Otherwise, we will remained victims of the circumstances thinking about what could have been done.

Notes:

1 Energy Intensity Methodology, UN.

2 Valleys of Death. The Breakthrough Institute, 2011. Ver

3 The Emission Gap Report 2015. UNEP, 2015

4 INSIDER: Why Are INDC Studies Reaching Different Temperature Estimates? World Resource Institute, 2015

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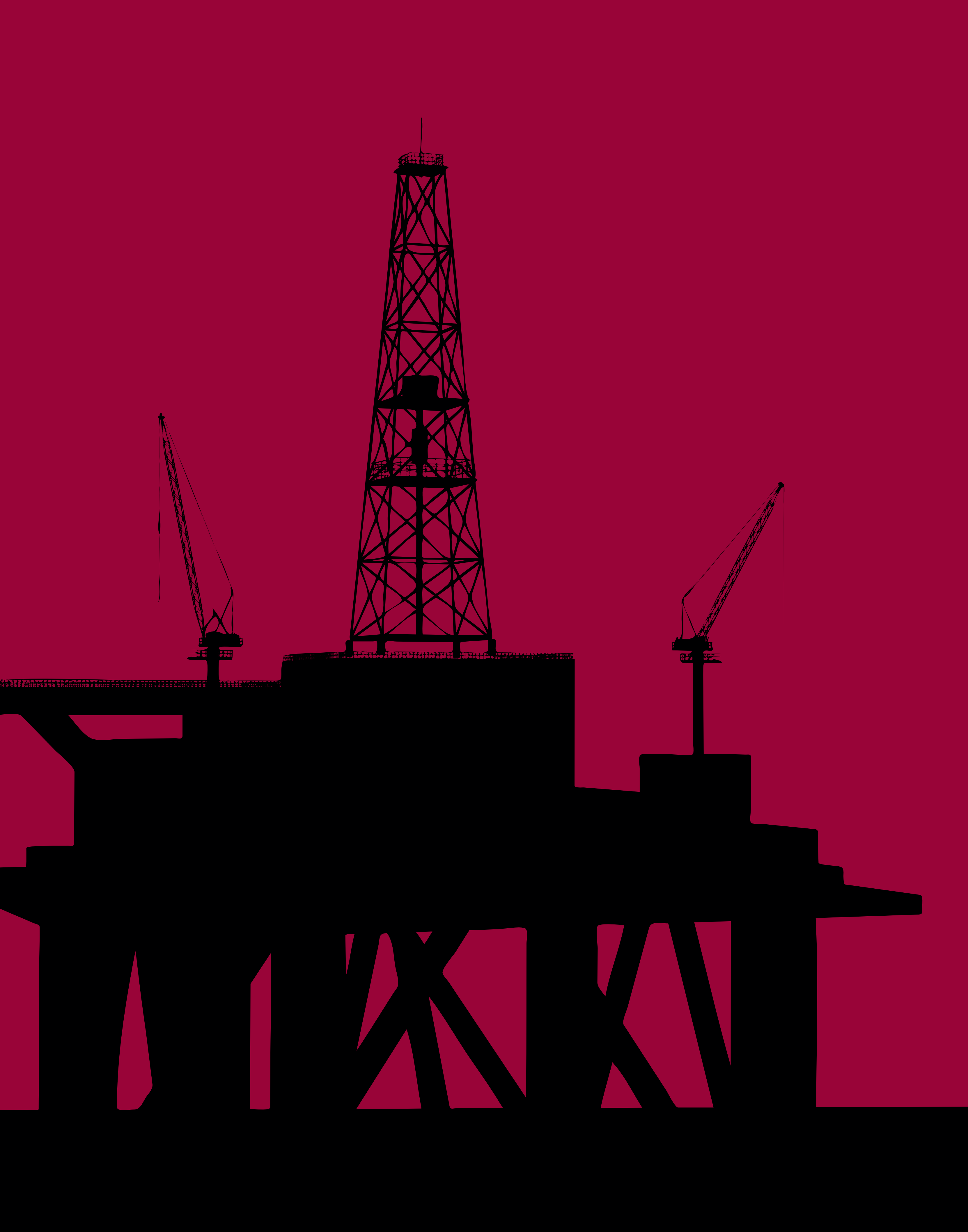

International Center on Energy and the Environment (CIEA).
It was created in 2005 to place IESA as the reference institution, at the national and regional level, in training of managers with leadership skills in the energy sector, being a center of excellence in reflection, generation and dissemination of knowledge on subjects related to energy and environment, with national and international scope.

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