PETROBRAS - PETROLEO BRASILEIRO SA
Form 20-F
April 29, 2013

As filed with the Securities and Exchange Commission on April 26, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 20-F
ANNUAL REPORT
PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

for the fiscal year ended December 31, 2012

Commission File Number 001-15106

Petróleo Brasileiro S.A.—Petrobras

(Exact name of registrant as specified in its charter)

Brazilian Petroleum Corporation—Petrobras

(Translation of registrant's name into English)

The Federative Republic of Brazil

(Jurisdiction of incorporation or organization)

Avenida República do Chile, 65

20031-912 – Rio de Janeiro – RJ – Brazil

(Address of principal executive offices)

Almir Guilherme Barbassa
(55 21) 3224-2040 – barbassa@petrobras.com.br
Avenida República do Chile, 65 – 23rd Floor
20031-912 – Rio de Janeiro – RJ – Brazil

(Name, telephone, e-mail and/or facsimile number and address of company contact person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class:	**Name of each exchange on which registered:**
Petrobras Common Shares, without par value*	New York Stock Exchange*
Petrobras American Depositary Shares, or ADSs (evidenced by American Depositary Receipts, or ADRs), each representing two Common Shares	New York Stock Exchange
Petrobras Preferred Shares, without par value*	New York Stock Exchange*
Petrobras American Depositary Shares (as evidenced by American Depositary Receipts), each representing two Preferred Shares	New York Stock Exchange
2.875% Global Notes due 2015, issued by PifCo	New York Stock Exchange
6.125% Global Notes due 2016, issued by PifCo	New York Stock Exchange
3.875% Global Notes due 2016, issued by PifCo	New York Stock Exchange
3.500% Global Notes due 2017, issued by PifCo	New York Stock Exchange
5.875% Global Notes due 2018, issued by PifCo	New York Stock Exchange
7.875% Global Notes due 2019, issued by PifCo	New York Stock Exchange
5.75% Global Notes due 2020, issued by PifCo	New York Stock Exchange
5.375% Global Notes due 2021, issued by PifCo	New York Stock Exchange
6.875% Global Notes due 2040, issued by PifCo	New York Stock Exchange
6.750% Global Notes due 2041, issued by PifCo	New York Stock Exchange

* Not for trading, but only in connection with the registration of American Depositary Shares pursuant to the requirements of the New York Stock Exchange.

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

TITLE OF EACH CLASS:

9.125% Global Notes due 2013, issued by PifCo

7.75% Global Notes due 2014, issued by PifCo

8.375% Global Notes due 2018, issued by PifCo

4.875% Global Notes due 2018, issued by PifCo

3.25% Global Notes due 2019, issued by PGF

5.875% Global Notes due 2022, issued by PifCo

4.25% Global Notes due 2023, issued by PGF

6.250% Global Notes due 2026, issued by PifCo

5.375% Global Notes due 2029, issued by PGF

The number of outstanding shares of each class of stock as of December 31, 2012 was:

7,442,454,142 Petrobras Common Shares, without par value

5,602,042,788 Petrobras Preferred Shares, without par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act.

Yes þ No ¨

If this report is an annual or transitional report, indicate by check mark if the registrant is not required to file reports pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ¨ No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer” in

Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ¨ International Financial Reporting Standards as issued by the International Accounting Standards Board R Other ¨

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ¨ Item 18 ¨

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No þ

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FORWARD-LOOKING STATEMENTS

Some of the information contained in this annual report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act, that are not based on historical facts and are not assurances of future results. Many of the forward-looking statements contained in this annual report may be identified by the use of forward-looking words, such as “believe,” “expect,” “anticipate,” “should,” “planned,” “estimate” and “potential,” among others. We have made forward-looking statements that address, among other things:

- our marketing and expansion strategy;
- our exploration and production activities, including drilling;
- our activities related to refining, import, export, transportation of petroleum, natural gas and oil products, petrochemicals, power generation, biofuels and other sources of renewable energy;
- our projected and targeted capital expenditures and other costs, commitments and revenues;
- our liquidity and sources of funding;
- development of additional revenue sources; and
- the impact, including cost, of acquisitions.

Our forward-looking statements are not guarantees of future performance and are subject to assumptions that may prove incorrect and to risks and uncertainties that are difficult to predict. Our actual results could differ materially from those expressed or forecast in any forward-looking statements as a result of a variety of factors. These factors include, among other things:

- our ability to obtain financing;
- general economic and business conditions, including crude oil and other commodity prices, refining margins and prevailing exchange rates;
- global economic conditions;
- our ability to find, acquire or gain access to additional reserves and to develop our current reserves successfully;

- uncertainties inherent in making estimates of our oil and gas reserves, including recently discovered oil and gas reserves;
- competition;
- technical difficulties in the operation of our equipment and the provision of our services;
- changes in, or failure to comply with, laws or regulations;
- receipt of governmental approvals and licenses;
- international and Brazilian political, economic and social developments;
- natural disasters, accidents, military operations, acts of sabotage, wars or embargoes;

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- the cost and availability of adequate insurance coverage; and
- other factors discussed below under "Risk Factors."

For additional information on factors that could cause our actual results to differ from expectations reflected in forward-looking statements, please see "Risk Factors" in this annual report.

All forward-looking statements attributed to us or a person acting on our behalf are qualified in their entirety by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information or future events or for any other reason.

The crude oil and natural gas reserve data presented or described in this annual report are only estimates and our actual production, revenues and expenditures with respect to our reserves may materially differ from these estimates.

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GLOSSARY OF PETROLEUM INDUSTRY TERMS

Unless the context indicates otherwise, the following terms have the meanings shown below:

ANEEL	The *Agência Nacional de Energia Elétrica* (National Electrical Energy Agency), or ANEEL, is the federal agency that regulates the electricity industry in Brazil.
ANP	The *Agência Nacional de Petróleo, Gás Natural e Biocombustíveis* (National Petroleum, Natural Gas and Biofuels Agency), or ANP, is the federal agency that regulates the oil, natural gas and renewable fuels industry in Brazil.
API	Standard measure of oil density developed by the American Petroleum Institute.
Barrels	Barrels of crude oil.
Condensate	Light hydrocarbon substances produced with natural gas, which condense into liquid at normal temperature and pressure.
CNPE	The *Conselho Nacional de Política Energética* (National Energy Policy Council), or CNPE, is an advisory body of the President of the Republic responsible for formulating energy policies and guidelines.
CVM	*The Comissão de Valores Mobiliários* (Securities and Exchange Commission) of Brazil.
Deep water	Between 300 and 1,500 meters (984 and 4,921 feet) deep.
Distillation	A process by which liquids are separated or refined by vaporization followed by condensation.
EWT	Extended well test.
Exploration area	A region in Brazil under a regulatory contract without a known hydrocarbon accumulation or with a hydrocarbon accumulation that has not yet been declared commercial.
FPSO	Floating Production, Storage and Offloading Unit.
Heavy (crude) oil	Crude oil with API density less than or equal to 22°.
Intermediate (crude) oil	Crude oil with API density higher than 22° and less than or equal to 31°.
Light (crude) oil	Crude oil with API density higher than 31°.
LNG	Liquefied natural gas.
LPG	Liquefied petroleum gas, which is a mixture of saturated and unsaturated hydrocarbons, with up to five carbon atoms, used as domestic fuel.
MME	The federal Ministry of Mines and Energy, or MME.
NGLs	Natural gas liquids, which are light hydrocarbon substances produced with natural gas, which condense into liquid at normal temperature and pressure.
Oil	Crude oil, including NGLs and condensates.

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Pre-salt reservoir	A geological formation containing oil or natural gas deposits located beneath a salt layer.
Post-salt reservoir	A geological formation containing oil or natural gas deposits located above a salt layer.
Proved reserves	Consistent with the definitions in the SEC's Amended Rule 4-10(a) of Regulation S-X, proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Existing economic conditions include prices and costs at which economic productibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to December 31, 2012, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or we must be reasonably certain that we will commence the project within a reasonable time. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
Proved developed reserves	Proved developed reserves are reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved undeveloped reserves	Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they

	are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Proved undeveloped reserves do not include reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.
SS	Semi-submersible unit.
Synthetic oil and synthetic gas	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
TLWP	Tension Leg Wellhead Platform.
Total depth	Total depth of a well, including vertical distance through water and below the mudline.
Ultra-deep water	Over 1,500 meters (4,921 feet) deep.

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TLWP	Tension Leg Wellhead Platform.
Total depth	Total depth of a well, including vertical distance through water and below the mudline.
Ultra-deep water	Over 1,500 meters (4,921 feet) deep.

CONVERSION TABLE

1 acre	=	0.004047 km^2		
1 barrel	=	42 U.S. gallons	=	Approximately 0.13 t of oil
1 boe	=	1 barrel of crude oil equivalent	=	6,000 cf of natural gas
1 m^3 of natural gas	=	35.315 cf	=	0.0059 boe
1 km	=	0.6214 miles		
1 km^2	=	247 acres		
1 meter	=	3.2808 feet		
1 t of crude oil	=	1,000 kilograms of crude oil	=	Approximately 7.5 barrels of crude oil (assuming an atmospheric pressure index gravity of 37° API)

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ABBREVIATIONS

bbl	Barrels
bn	Billion (thousand million)
bnbbl	Billion barrels
bncf	Billion cubic feet
bnm^3	Billion cubic meters
boe	Barrels of oil equivalent
bbl/d	Barrels per day
cf	Cubic feet
GWh	One gigawatt of power supplied or demanded for one hour
km	Kilometer
km^2	Square kilometers
m^3	Cubic meter
mbbl	Thousand barrels
mbbl/d	Thousand barrels per day
mboe	Thousand barrels of oil equivalent
mboe/d	Thousand barrels of oil equivalent per day
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mm^3	Thousand cubic meters
mm^3/d	Thousand cubic meters per day
mm^3/y	Thousand cubic meter per year
mmbbl	Million barrels
mmbbl/d	Million barrels per day
mmboe	Million barrels of oil equivalent
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
mmm^3	Million cubic meters
mmm^3/d	Million cubic meters per day
mmt	Million metric tons
mmt/y	Million metric tons per year
MW	Megawatts
MWavg	Amount of energy (in MWh) divided by the time (in hours) in which such energy is produced or consumed
MWh	One megawatt of power supplied or demanded for one hour
ppm	Parts per million
P$	Argentine pesos
R$	Brazilian *reais*
t	Metric ton
Tcf	Trillion cubic feet
U.S.$	United States dollars
/d	Per day

/y	Per year

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PRESENTATION OF FINANCIAL AND OTHER INFORMATION

This is the annual report of Petróleo Brasileiro S.A.—Petrobras, or Petrobras. Unless the context otherwise requires, the terms “Petrobras,” “we,” “us,” and “our” refer to Petróleo Brasileiro S.A.—Petrobras and its consolidated subsidiaries and special purpose entities.

We issue notes in the capital markets through our wholly-owned finance subsidiaries Petrobras International Finance Company, or PifCo, a Cayman Islands company, and Petrobras Global Finance B.V., or PGF, a Dutch company. We fully and unconditionally guarantee the notes issued by PGF and PifCo. PGF is not required to file periodic reports with the Securities and Exchange Commission, or SEC, and PifCo no longer has an obligation to file periodic reports with the SEC. See Note 35 to our audited consolidated financial statements. The last 20-F filed by PifCo with the SEC in connection with the year ended December 31, 2011 was filed on April 2, 2012, as amended on July 9, 2012.

In this annual report, references to “real,” “reais” or “R$” are to Brazilian *reais* and references to “U.S. dollars” or “U.S.$” are to the United States dollars. Certain figures included in this annual report have been subject to rounding adjustments; accordingly, figures shown as totals in certain tables may not be an exact arithmetic aggregation of the figures that precede them.

The audited consolidated financial statements of Petrobras and our consolidated subsidiaries as of and for each of the three years ended December 31, 2012, 2011 and 2010 and the accompanying notes contained in this annual report have been presented in U.S. dollars and prepared in accordance with International Financial Reporting Standards, or IFRS, issued by the International Accounting Standards Board, or IASB. See Item 5. “Operating and Financial Review and Prospects” and Note 2 to our audited consolidated financial statements. Petrobras applies IFRS in its statutory financial statements prepared in accordance with Brazilian Corporate Law and regulations promulgated by the *Comissão de Valores Mobiliários* (Securities and Exchange Commission of Brazil, or CVM). Brazilian Corporate Law was amended in 2007 to permit accounting practices adopted in Brazil (Brazilian GAAP) to converge with IFRS.

Our IFRS financial statements filed with the local securities regulator in Brazil use the *real* as its presentation currency, while the financial statements included herein use the U.S. Dollar as its presentation currency. The functional currency of Petrobras and all Brazilian subsidiaries is the Brazilian *real*; the functional currency of PifCo, PGF and certain subsidiaries and special purpose entities that operate in the international economic environment is the U.S. dollar; and the functional currency of Petrobras Argentina is the Argentine peso. As described more fully in Note 2.3 to our audited consolidated financial statements, the U.S. dollar amounts for the periods presented have been translated from the Brazilian *real* amounts in accordance with the criteria set forth in IAS 21 – “The effects of changes in foreign exchange rates.” Based on IAS 21, we have translated all assets and liabilities into U.S. dollars at the exchange rate as of the date of the balance sheet and all accounts in the statement of income and statement of cash flows at the average rates prevailing during the year.

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Unless the context otherwise indicates:

- historical data contained in this annual report that were not derived from the audited consolidated financial statements have been translated from *reais* on a similar basis;

- forward-looking amounts, including estimated future capital expenditures and investments, have all been based on our Petrobras 2020 Strategic Plan, which covers the period from 2009 to 2020, and on our 2013-2017 Business and Management Plan, and have been projected on a constant basis and have been translated from *reais* at an estimated average exchange rate of R$2.00 to U.S.$1.00 in 2013, and the *reais* strengthening against the U.S. dollar to R$1.85 in the long term, in accordance with our 2013-2017 Business and Management Plan. In addition, in accordance with our 2013-2017 Business and Management Plan, future calculations involving an assumed price of crude oil have been calculated using a Brent crude oil price of U.S.$107.00 for 2013, declining to U.S.$100.00 in the long term, adjusted for our quality and location differences, unless otherwise stated; and

- estimated future capital expenditures and investments are based on the most recently budgeted amounts, which may not have been adjusted to reflect all factors that could affect such amounts.

PRESENTATION OF INFORMATION CONCERNING RESERVES

Petrobras continues to utilize the SEC rules for estimating and disclosing oil and gas reserve quantities included in this annual report. In accordance with these rules, adopted by Petrobras at year-end 2009, reserve volumes have been estimated using the average prices calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period and include non-traditional reserves, such as synthetic oil and gas. In addition, the amended rules also adopted a reliable technology definition that permits reserves to be added based on field-tested technologies. The adoption of the SEC's rules for estimating and disclosing oil and gas reserves and the FASB's issuance of the Accounting Standards Update No. 2010-03 "Oil and Gas Reserve Estimation and Disclosure" in January 2010 generated no material impact on our reported reserves or on our consolidated financial position or results of operations.

DeGolyer and MacNaughton (D&M) used our reserves estimates to conduct a reserves audit of 93% of the net proved crude oil, condensate and natural gas reserves as of December 31, 2012 from certain properties we own in Brazil. In addition, D&M used its own estimates of our reserves to conduct a reserves evaluation of 100% of the net proved crude oil, condensate, NGL and natural gas reserves as of December 31, 2012 from the properties we operate in Argentina. Furthermore, D&M used our reserves estimates to conduct a reserves audit of 98% of the net proved crude oil, condensate and natural gas reserves as of December 31, 2012 from certain properties we operate in North and South America (other than Brazil and Argentina). The reserves estimates were prepared in accordance with the reserves definitions of Rule 4-10(a) of Regulation S-X of the SEC. All reserves estimates involve some degree of uncertainty. See Item 3. “Key Information—Risk Factors—Risks Relating to Our Operations” for a description of the risks relating to our reserves and our reserve estimates.

On January 15, 2013, we filed reserve estimates for Brazil with the ANP, in accordance with Brazilian rules and regulations, totaling net volumes of 13.3 billion barrels of crude oil and condensate and 14.7 trillion cubic feet of natural gas. The reserve estimates filed with the ANP and those provided herein differ by approximately 22% in terms of oil equivalent. This difference is due to: (i) the ANP requirement to estimate proved reserves through the technical-economical abandonment of production wells, as opposed to limiting reserve estimates to the life of the concession contracts as required by Rule 4-10 of Regulation S-X; and (ii) different technical criteria for booking proved reserves, including the use of current oil prices as opposed to the SEC requirement that the 12-month average price be used to determine the economic producibility of reserves in Brazil.

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We also file reserve estimates from our international operations with various governmental agencies under the guidelines of the Society of Petroleum Engineers, or SPE. The aggregate reserve estimates from our international operations, under SPE guidelines, amounted to 0.5 bnbbl of crude oil, condensate and NGLs and 1.3 trillion cubic feet of natural gas as of December 31, 2012, which is approximately 14% higher than the reserve estimates calculated under Regulation S-X, as provided herein. This difference occurs because of different technical criteria for booking proved reserves, including the use of current oil prices as opposed to the SEC requirement that the 12-month average price be used to determine the economic producibility of international reserves.

PART I

Item 1. Identity of Directors, Senior Management and Advisers

Not applicable.

Item 2. Offer Statistics and Expected Timetable

Not applicable.

Item 3. Key Information

Selected Financial Data

This section contains selected consolidated financial data, presented in U.S. dollars and prepared in accordance with IFRS as of and for each of the four years ended December 31, 2012, 2011, 2010 and 2009, derived from our audited consolidated financial statements, which were audited by PricewaterhouseCoopers Auditores Independentes–PwC for the year ended December 31, 2012 and KPMG Auditores Independentes for the three years ended December 31, 2011, 2010 and 2009.

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The information below should be read in conjunction with, and is qualified in its entirety by reference to, our audited consolidated financial statements and the accompanying notes and Item 5. "Operating and Financial Review and Prospects."

BALANCE SHEET DATA

IFRS Summary Financial Data

	As of December 31,			
	2012	**2011**	**2010**	**2009**
		(U.S.$ million)		
Assets:				
Cash and cash equivalents	13,520	19,057	17,655	16,222
Marketable securities	10,431	8,961	15,612	77
Trade and other receivables, net	11,099	11,756	10,845	8,147
Inventories	14,552	15,165	11,808	11,103
Other current assets	8,192	9,653	7,639	6,629
Long-term receivables	23,105	22,462	22,637	19,991
Investments	6,106	6,530	6,957	4,620
Property, plant and equipment	204,901	182,918	168,104	128,754
Intangible assets	39,739	43,412	48,937	3,899
Total assets	**331,645**	**319,914**	**310,194**	**199,442**
Liabilities and shareholders' equity:				
Total current liabilities	34,070	36,364	33,577	31,067
Non-current liabilities(1)	40,052	33,722	30,251	23,809
Long-term debt(2)	88,484	72,718	60,417	48,963
Total liabilities	**162,606**	**142,804**	**124,245**	**103,839**
Shareholders' equity				
Share capital	107,362	107,355	107,341	33,790
Reserves and other comprehensive income	60,525	68,483	76,769	60,579
Petrobras' shareholders' equity	167,887	175,838	184,110	94,369
Non-controlling interests	1,152	1,272	1,839	1,234
Total equity	**169,039**	**177,110**	**185,949**	**95,603**
Total liabilities and shareholders' equity	**331,645**	**319,914**	**310,194**	**199,442**

(1) Excludes long-term debt.

(2) Excludes current portion of long-term debt.

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INCOME STATEMENT DATA

IFRS Summary Financial Data

	For the Year Ended December 31,			
	2012	2011	2010	2009
	(U.S.$ million, except for share and per share data)			
Sales revenues	144,103	145,915	120,452	91,146
Net income before financial results, profit sharing and income taxes	16,900	27,285	26,372	22,923
Net income attributable to the shareholders of Petrobras	11,034	20,121	20,055	15,308
Weighted average number of shares outstanding:				
Common	7,442,454,142	7,442,454,142	5,683,061,430	5,073,347,344
Preferred	5,602,042,788	5,602,042,788	4,189,764,635	3,700,729,396
Net income before financial results, profit sharing and income taxes per:				
Common and Preferred Shares	1.30	2.09	2.67	2.61
Common and Preferred ADS	2.60	4.18	5.34	5.22
Basic and diluted earnings per:				
Common and Preferred Shares	0.85	1.54	2.03	1.74
Common and Preferred ADS	1.70	3.08	4.06	3.48
Cash dividends per:(1)				
Common and Preferred shares	0.34	0.53	0.70	0.59
Common and Preferred ADS	0.68	1.06	1.40	1.18

(1) Represents dividends paid during the year.

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RISK FACTORS

Risks Relating to Our Operations

Exploration and production of oil in deep and ultra-deep waters involves risks.

Exploration and production of oil involves risks that are increased when carried out in deep and ultra-deep waters. The majority of our exploration and production activities are carried out in deep and ultra-deep waters, and the proportion of our deepwater activities will remain constant or increase due to the location of our pre-salt reservoirs in deep and ultra-deep waters. Our activities, particularly in deep and ultra-deep waters, present several risks, such as the risk of oil spills, explosions in platforms and drilling operations and natural disasters. The occurrence of any of these events or other incidents could result in personal injuries, loss of life, severe environmental damage with the resulting containment, clean-up and repair expenses, equipment damage and liability in civil and administrative proceedings.

Our insurance policies do not cover all liabilities, and insurance may not be available for all risks. There can be no assurance that incidents will not occur in the future, that insurance will adequately cover the entire scope or extent of our losses or that we will not be found liable in connection with claims arising from these and other events.

International prices for oil and oil products are volatile, and have a significant effect on us. We may not adjust our prices for products sold in Brazil when the international prices of crude oil and oil products increases, or when the Real in relation to the U.S. Dollar depreciates, which could have a negative impact on our results of operations.

The majority of our revenue is derived primarily from sales of crude oil and oil products in Brazil and, to a lesser extent, natural gas. Changes in crude oil prices typically result in changes in prices for oil products and natural gas. Historically, international prices for crude oil, oil products and natural gas have fluctuated widely as a result of many global and regional factors. Volatility and uncertainty in international prices for crude oil, oil products and natural gas may continue. Substantial or extended declines in international crude oil prices may have a material adverse effect on our business, results of operations and financial condition, and the value of our proved reserves.

Our pricing policy in Brazil seeks to align the price of oil products with international prices over the long term, however we do not necessarily adjust our prices for diesel, gasoline and other products to reflect oil price volatility in the international markets or short term movements in the value of the *real*. Based on the decisions of the Brazilian federal government as our controlling shareholder we have, and may continue to have, periods during which our products will not be at parity with international product prices (See Item 3. “Risk Factors—Risks Relating to Our Relationship with the Brazilian Federal Government—The

Brazilian federal government, as our controlling shareholder, may cause us to pursue certain macroeconomic and social objectives that may have a material adverse effect on us.”).

As a result, when we are a net importer by volume of oil and oil products to meet the Brazilian demand, increases in the price of crude oil in the international markets may have a negative impact on our costs of sales and margins, since the cost to acquire such oil and oil products may exceed the price at which we are able to sell these products in Brazil. A similar effect occurs when the *real* depreciates in relation to the U.S. dollar, as we sell oil and oil products in Brazil in *reais* and international prices for crude oil and oil products are set in U.S. dollars. A depreciation of the *real* increases our cost of imported oil and oil products, without a corresponding increase in our revenues unless we are able to increase the price at which we sell products in Brazil.

Our ability to maintain our long-term growth objectives for oil production depends on our ability to successfully develop our reserves, and failure to do so could prevent us from achieving our long-term goals for growth in production.

Our ability to maintain our long-term growth objectives for oil production, including those defined in our 2013-2017 Business and Management Plan, is highly dependent upon our ability to successfully develop our existing reserves and, in the long term, upon our ability to obtain additional reserves. The development of the sizable reservoirs in deep and ultra-deep waters, including the pre-salt reservoirs that have been assigned to us by the Brazilian federal government, has demanded and will continue to demand significant capital investments. A primary operational challenge, particularly for the pre-salt reservoirs, will be allocating our resources to build the necessary infrastructure at considerable distances from the shore and securing a qualified labor force and offshore oil services to develop reservoirs of such size and magnitude in a timely manner. We cannot guarantee that we will have or will be able to obtain, in the time frame that we expect, sufficient resources necessary to exploit the reservoirs in deep and ultra-deep waters that the Brazilian federal government has licensed and assigned to us, or that it may license to us in the future, including as a result of the enactment of the new regulatory model for the oil and gas industry in Brazil.

Our exploration activities also expose us to the inherent risks of drilling, including the risk that we will not discover commercially productive crude oil or natural gas reserves. The costs of drilling wells are often uncertain, and numerous factors beyond our control (such as unexpected drilling conditions, equipment failures or incidents, and shortages or delays in the availability of drilling rigs and the delivery of equipment) may cause drilling operations to be curtailed, delayed or cancelled. In addition, increased competition in the oil and gas sector in Brazil may increase the costs of obtaining additional acreage in bidding rounds for new concessions. We may not be able to maintain our long-term growth objectives for oil production unless we conduct successful exploration and development activities of our large reservoirs in a timely manner.

We may not obtain, or it may be difficult for us to obtain, financing for our planned investments, which may have a material adverse effect on us.

Under our 2013-2017 Business and Management Plan, we intend to invest U.S.$236.7 billion from 2013 to 2017, U.S.$207.1 billion of which is for projects already under implementation, while U.S.$29.6 billion is for projects that are still under evaluation and subject to final approval by our management. In addition, approximately 19% of our existing debt (principal), or U.S.$17.8 billion, will mature in the next three years. In order to implement our 2013-2017 Business and Management Plan, including the development of our oil and natural gas exploration activities in the pre- and post-salt layers and the development of refining capacity sufficient to process increasing production volumes, we will need to raise significant amounts of debt capital in the financial and capital markets, including by, among other means, loans and issuing debt securities. We cannot guarantee that we will be able to obtain the necessary financing to implement our Business and Management Plan and to roll-over our existing debt in a timely and advantageous manner in order to implement our 2013-2017 Business and Management Plan.

Our crude oil and natural gas reserve estimates involve some degree of uncertainty, which could adversely affect our ability to generate income.

The proved crude oil and natural gas reserves set forth in this annual report are our estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made) according to applicable regulations. Our proved developed crude oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties in estimating quantities of proved reserves related to prevailing crude oil and natural gas prices applicable to our production, which may lead us to make revisions to our reserve estimates. Downward revisions in our reserve estimates could lead to lower future production, which could have an adverse effect on our results of operations and financial condition.

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We do not own any of the subsoil accumulations of crude oil and natural gas in Brazil.

Under Brazilian law, the Brazilian federal government owns all subsoil accumulations of crude oil and natural gas in Brazil and the concessionaire owns the oil and gas it produces from those subsoil accumulations pursuant to concession agreements. We possess the exclusive right to develop the volumes of crude oil and natural gas included in our reserves pursuant to concession agreements awarded to us by the Brazilian federal government and we own the hydrocarbons we produce under those concession agreements. Access to crude oil and natural gas reserves is essential to an oil and gas company's sustained production and generation of income, and our ability to generate income would be adversely affected if the Brazilian federal government were to restrict or prevent us from exploiting these crude oil and natural gas reserves. In addition, we may be subject to fines by the ANP and our concessions may be revoked if we do not comply with our obligations under our concessions.

The Assignment Agreement we entered into with the Brazilian federal government is a related party transaction subject to future price readjustment.

The transfer of oil and gas exploration and production rights to us related to specific pre-salt areas is governed by the Assignment Agreement, which is a contract between the Brazilian federal government, our controlling shareholder, and us. The negotiation of the Assignment Agreement involved significant issues, including negotiations regarding (1) the area covered by the assignment of rights, consisting of exploratory blocks; (2) the volume, on a barrel of oil equivalent basis, that we can extract from this area; (3) the price to be paid for the assignment of rights; (4) the terms of the subsequent revision of the contract price and volume under the Assignment Agreement; and (5) the terms of the reallocation of volumes among the exploratory blocks assigned to us.

This contract includes provisions for a subsequent revision of the contract terms, including the price we paid for the rights we acquired under the Assignment Agreement. The future negotiation with the Brazilian federal government will be conducted in accordance with the terms of the Assignment Agreement and will be based on a number of factors, including the international value of the crude oil at the time of the declaration of commerciality of the relevant pre-salt area. At the time the Assignment Agreement was negotiated, the initial contract price paid by us was based on an assumed Brent oil crude price of approximately U.S.$80. Once the revision process is concluded pursuant to the terms of the Assignment Agreement, if it is determined that the revised contract price is higher than the initial contract price, we will either make an additional payment to the Brazilian federal government or reduce the amount of barrels of oil equivalent subject to the Assignment Agreement.

See Item 10. "Material contracts—Assignment Agreement." Over the course of the life of the Assignment Agreement, novel issues may arise in the implementation of the revision process and other provisions that will require negotiations between related parties.

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We are subject to numerous environmental, health and safety regulations and industry standards that are becoming more stringent and may result in increased capital and operating expenditures and decreased production.

Our activities are subject to a wide variety of federal, state and local laws, regulations and permit requirements relating to the protection of human health, safety and the environment, both in Brazil and in other jurisdictions in which we operate, as well as to evolving industry standards and best practices. Particularly in Brazil, our oil and gas business is subject to extensive regulation by several governmental agencies, including the ANP, the ANEEL, the *Agência Nacional de Transportes Aquaviários* (Brazilian Water Transportation Agency), or ANTAQ and the *Agência Nacional de Transportes Terrestres* (Brazilian Land Transportation Agency), or ANTT. Failure to observe or comply with these laws and regulations could result in penalties that could adversely affect our operations. In Brazil, for example, we could be exposed to administrative and criminal sanctions, including warnings, fines and closure orders for non-compliance with these environmental, health and safety regulations, which, among other things, limit or prohibit emissions or spills of toxic substances produced in connection with our operations. Waste disposal and emissions regulations may also require us to clean up or retrofit our facilities at substantial cost and could result in substantial liabilities. The *Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais Renováveis* (Brazilian Institute of the Environment and Renewable Natural Resources, or IBAMA) and the ANP routinely inspect our facilities, and may impose fines, restrictions on operations, or other sanctions in connection with its inspections, including unexpected, temporary production shutdowns and delays resulting in decreased production. In addition, we are subject to environmental laws that require us to incur significant costs to cover damage that a project may cause to the environment. These additional costs may have a negative impact on the profitability of the projects we intend to implement or may make such projects economically unfeasible.

As environmental, health and safety regulations become more stringent, and as new laws and regulations relating to climate change, including carbon controls, become applicable to us, and as industry standards evolve, it is probable that our capital expenditures and investments for compliance with such laws and regulations and industry standards will increase substantially in the future. In addition, if compliance with such laws and regulations and industry standards results in significant unplanned production shutdowns, this may have a material adverse effect on our production. We also cannot guarantee that we will be able to maintain or renew our licenses and permits if they are revoked or if the applicable environmental authorities oppose or delay their issuance or renewal. Increased expenditures to comply with environmental, health and safety regulations, to mitigate the environmental impact of our operations or to restore the biological and geological characteristics of the areas in which we operate may result in reductions in other strategic investments. Any substantial increase in expenditures for compliance with environmental, health or safety regulations or reduction in strategic investments and significant decreases in our production from unplanned shutdowns may have a material adverse effect on our results of operations or financial condition.

We may incur losses and spend time and money defending pending litigations and arbitrations.

We are currently a party to numerous legal proceedings relating to civil, administrative, environmental, labor and tax claims filed against us. These claims involve substantial amounts of money and other remedies. Several individual disputes account for a significant part of the total amount of claims against us. See Item 8. "Financial Information—Legal Proceedings" and Note 27 to our audited consolidated financial statements included in this annual report for a description of the legal proceedings to which we are subject. In the event that claims involving a material amount and for which we have no provisions were to be decided against us, or in the event that the losses estimated turn out to be significantly higher than the provisions made, the aggregate cost of unfavorable decisions could have a material adverse effect on our financial condition and results of operations. We may also be subject to litigation and administrative proceedings in connection with our concessions and other government authorizations, which could result in the revocation of such concessions and government authorizations. In addition, our management may be required to direct its time and attention to defending these claims, which could preclude them from focusing on our core business. Depending on the outcome, certain litigation could result in restrictions on our operations and have a material adverse effect on certain of our businesses.

We are vulnerable to increased financing expenses resulting from depreciation of the real in relation to the U.S. dollar and increases in prevailing market interest rates.

Fluctuations in exchange rates, especially a depreciation of the *real* in relation to the U.S. dollar rate, may increase our financing expenses as most of our revenues have been denominated in *reais*, while some of our operating expenses and capital expenditures and investments and a substantial portion of our indebtedness are, and are expected to continue to be, denominated in or indexed to U.S. dollars and other foreign currencies. In addition, our net liability position in foreign currencies that are subject to monetary valuation has increased over time. As of December 31, 2012, our net liability position in foreign currency increased to approximately U.S.$49,513 million compared to U.S.$29,627 million as of December 31, 2011. In a year as 2012 during which the U.S. dollar appreciated 14.3% in relation to the *real*, this appreciation resulted in an additional U.S.$3,278 million in finance expense to us from foreign exchange variation of our debt.

As of December 31, 2012, approximately 50% — U.S.$47,889 million of our total indebtedness — consisted of floating rate debt. In light of cost considerations and market analysis, we decided not to enter into derivative contracts or make other arrangements to hedge against the risk of an increase in interest rates. Accordingly, if market interest rates rise, our financing expenses will increase, which could have an adverse effect on our results of operations and financial condition. In addition, as we refinance our existing debt in the coming years, the mix of our indebtedness may change, specifically as it relates to the ratio of fixed to floating interest rates, the ratio of short-term to long-term debt, and the currencies in which our debt is denominated in or indexed to. We cannot assure you that such changes will not result in increased financing expenses borne by us.

We are not insured against business interruption for our Brazilian operations and most of our assets are not insured against war or sabotage.

We do not maintain coverage for business interruptions of any nature for our Brazilian operations, including business interruptions caused by labor action. If, for instance, our workers were to strike, the resulting work stoppages could have an adverse effect on us. In addition, we do not insure most of our assets against war or sabotage. Therefore, an attack or an operational incident causing an interruption of our business could have a material adverse effect on our financial condition or results of operations.

Risks Relating to Our Relationship with the Brazilian Federal Government

The Brazilian federal government, as our controlling shareholder, may cause us to pursue certain macroeconomic and social objectives that may have a material adverse effect on us.

As our controlling shareholder, the Brazilian federal government has pursued, and may pursue in the future, certain of its macroeconomic and social objectives through us, as permitted by law. Brazilian law requires the Brazilian federal government to own a majority of our voting stock, and so long as it does, the Brazilian federal government will have the power to elect a majority of the members of our board of directors and, through them, a majority of the executive officers who are responsible for our day-to-day management. As a result, we may engage in activities that give preference to the objectives of the Brazilian federal government rather than to our own economic and business objectives.

In particular, we continue to assist the Brazilian federal government to ensure that the supply and pricing of crude oil and oil products in Brazil meets Brazilian consumption requirements. Accordingly, we may make investments, incur costs and engage in sales on terms that may have an adverse effect on our results of operations and financial condition. Prior to January 2002, prices for crude oil and oil products were regulated by the Brazilian federal government, occasionally set below prices prevailing in the world oil markets. We cannot assure you that price controls will not be reinstated in Brazil.

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Our investment budget is subject to approval by the Brazilian federal government, and failure to obtain approval of our planned investments could adversely affect our operating results and financial condition.

The Brazilian federal government maintains control over our investment budget and establishes limits on our investments and long-term debt. As a state-controlled entity, we must submit our proposed annual budgets to the Ministry of Planning, Budget and Management, the MME and the Brazilian Congress for approval. If our approved budget reduces our proposed investments and incurrence of new debt and we cannot obtain financing that does not require Brazilian federal government approval, we may not be able to make all the investments we envision, including those we have agreed to make to expand and develop our crude oil and natural gas fields. If we are unable to make these investments, our operating results and financial condition may be adversely affected.

Risks Relating to Brazil

Brazilian political and economic conditions have a direct impact on our business and may have a material adverse effect on us.

The Brazilian federal government's economic policies may have important effects on Brazilian companies, including us, and on market conditions and prices of Brazilian securities. Our financial condition and results of operations may be adversely affected by the following factors and the Brazilian federal government's response to these factors:

- devaluations and other exchange rate movements;
- inflation;
- exchange control policies;
- price instability;
- interest rates;
- liquidity of domestic capital and lending markets;
- tax policy;
- regulatory policy for the oil and gas industry, including pricing policy; and
- other political, diplomatic, social and economic developments in or affecting Brazil.

Uncertainty over whether the Brazilian federal government will implement changes in policy or regulations that may affect any of the factors mentioned above or other factors in the future may lead to economic uncertainty in Brazil and increase the volatility of the Brazilian securities market and securities issued abroad by Brazilian companies, which may have a material adverse effect on our results of operations and financial condition.

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Risks Relating to Our Equity and Debt Securities

The size, volatility, liquidity and/or regulation of the Brazilian securities markets may curb the ability of holders of ADSs to sell the common or preferred shares underlying our ADSs.

Petrobras shares are among the most liquid in the São Paulo Stock Exchange, or BM&FBOVESPA, but overall, the Brazilian securities markets are smaller, more volatile and less liquid than the major securities markets in the United States and other jurisdictions, and may be regulated differently from the way in which U.S. investors are accustomed. Factors that may specifically affect the Brazilian equity markets may limit the ability of holders of ADSs to sell the common or preferred shares underlying our ADSs at the price and time they desire.

The market for PifCo's and PGF's notes may not be liquid.

Some of PifCo's notes are not listed on any securities exchange and are not quoted through an automated quotation system. PGF's notes are currently only listed on the Luxembourg Stock Exchange and trade on the Euro MTF market. PGF can issue new notes which can be listed in markets other than the Luxembourg Stock Exchange and traded in markets other than the Euro MTF market. We can make no assurance as to the liquidity of or trading markets for PifCo's notes or PGF's notes. We cannot guarantee that the holders of PifCo's notes or PGF's notes will be able to sell their notes in the future. If a market for PifCo's notes or PGF's notes does not develop, holders of PifCo's notes or PGF's notes may not be able to resell the notes for an extended period of time, if at all.

Holders of ADSs may be unable to exercise preemptive rights with respect to the common or preferred shares underlying the ADSs.

Holders of ADSs who are residents of the United States may not be able to exercise the preemptive rights relating to the common or preferred shares underlying our ADSs unless a registration statement under the Securities Act is effective with respect to those rights or an exemption from the registration requirements of the Securities Act is available. We are not obligated to file a registration statement with respect to the common or preferred shares relating to these preemptive rights, and therefore we may not file any such registration statement. If a registration statement is not filed and an exemption from registration does not exist, The Bank of New York Mellon, as depositary, will attempt to sell the preemptive rights, and holders of ADSs will be entitled to receive the proceeds of the sale. However, the preemptive rights will expire if the depositary cannot sell them. For a more complete description of preemptive rights with respect to the common or preferred shares, see Item 10. "Additional Information—Memorandum and Articles of Incorporation—Preemptive Rights."

If holders of our ADSs exchange their ADSs for common or preferred shares, they risk losing the ability to remit foreign currency abroad and forfeiting Brazilian tax advantages.

The Brazilian custodian for our common or preferred shares underlying our ADSs must obtain a certificate of registration from the Central Bank of Brazil to be entitled to remit U.S. dollars abroad for payments of dividends and other distributions relating to our preferred and common shares or upon the disposition of the common or preferred shares. If holders of ADSs decide to exchange their ADSs for the underlying common or preferred shares, they will be entitled to continue to rely, for five Brazilian business days from the date of exchange, on the custodian's certificate of registration. After that period, such holders may not be able to obtain and remit U.S. dollars abroad upon the disposition of the common or preferred shares, or distributions relating to the common or preferred shares, unless they obtain their own certificate of registration or register under Resolution No. 2,689, of January 26, 2000, of the National Monetary Council (*Conselho Monetário Nacional*, or CMN), which entitles registered foreign investors to buy and sell on the BM&FBOVESPA. In addition, if such holders do not obtain a certificate of registration or register under Resolution No. 2,689, they may be subject to less favorable tax treatment on gains with respect to the common or preferred shares.

If such holders attempt to obtain their own certificate of registration, they may incur expenses or suffer delays in the application process, which could delay their ability to receive dividends or distributions relating to the common or preferred shares or the return of their capital in a timely manner. The custodian's certificate of registration or any foreign capital registration obtained by such holders may be affected by future legislative or regulatory changes and we cannot assure such holders that additional restrictions applicable to them, the disposition of the underlying common or preferred shares, or the repatriation of the proceeds from the process will not be imposed in the future.

Holders of ADSs may face difficulties in protecting their interests.

Our corporate affairs are governed by our bylaws and Brazilian Corporate Law, which differ from the legal principles that would apply if we were incorporated in a jurisdiction in the United States or elsewhere outside Brazil. In addition, the rights of an ADS holder, which are derivative of the rights of holders of our common or preferred shares, as the case may be, to protect their interests against actions by our board of directors are different under Brazilian Corporate Law than under the laws of other jurisdictions. Rules against insider trading and self-dealing and the preservation of shareholder interests may also be different in Brazil than in the United States. In addition, shareholders in Brazilian companies ordinarily do not have standing to bring a class action.

We are a state-controlled company organized under the laws of Brazil and all of our directors and officers reside in Brazil. Substantially all of our assets and those of our directors and officers are located in Brazil. As a result, it may not be possible for holders of ADSs to effect service of process upon us or our directors and officers within the United States or other jurisdictions outside Brazil or to enforce against us or our directors and officers judgments obtained in the United States or other jurisdictions outside Brazil. Because judgments of U.S. courts for civil liabilities based upon the U.S. federal securities laws may only be enforced in Brazil if certain requirements are met, holders of ADSs may face greater difficulties in protecting their interest in actions against us or our directors and officers than would shareholders of a corporation incorporated in a state or other jurisdiction of the United States.

Holders of our ADSs do not have the same voting rights as our shareholders. In addition, holders of ADSs representing preferred shares generally do not have voting rights.

Holders of our ADSs do not have the same voting rights as holders of our shares. Holders of our ADSs are entitled to the contractual rights set forth for their benefit under the deposit agreements. ADS holders exercise voting rights by providing instructions to the depositary, as opposed to attending shareholders meetings or voting by other means available to shareholders. In practice, the ability of a holder of ADSs to instruct the depositary as to voting will depend on the timing and procedures for providing instructions to the depositary, either directly or through the holder's custodian and clearing system.

In addition, a portion of our ADSs represents our preferred shares. Under Brazilian law and our bylaws, holders of preferred shares generally do not have the right to vote in meetings of our stockholders. This means, among other things, that holders of ADSs representing preferred shares are not entitled to vote on important corporate transactions or decisions. See Item 10. “Additional Information—Memorandum and Articles of Incorporation—Voting Rights” for a discussion of the limited voting rights of our preferred shares.

We would be required to pay judgments of Brazilian courts enforcing our obligations under the guaranty relating to PifCo’s notes or PGF’s notes only in reais.

If proceedings were brought in Brazil seeking to enforce our obligations in respect of the guaranty relating to PifCo’s notes or PGF’s notes, we would be required to discharge our obligations only in *reais*. Under the Brazilian exchange control rules, an obligation to pay amounts denominated in a currency other than *reais*, which is payable in Brazil pursuant to a decision of a Brazilian court, may be satisfied in *reais* at the rate of exchange, as determined by the Central Bank of Brazil, in effect on the date of payment.

A finding that we are subject to U.S. bankruptcy laws and that the guaranty executed by us were a fraudulent conveyance could result in PifCo noteholders or PGF noteholders losing their legal claim against us.

PifCo's and PGF's obligation to make payments on the PifCo notes and the PGF notes, respectively, is supported by our obligation under the corresponding guaranty. We have been advised by our external U.S. counsel that the guaranty is valid and enforceable in accordance with the laws of the State of New York and the United States. In addition, we have been advised by our general counsel that the laws of Brazil do not prevent the guaranty from being valid, binding and enforceable against us in accordance with its terms. In the event that U.S. federal fraudulent conveyance or similar laws are applied to the guaranty, and we, at the time we entered into the relevant guaranty:

- were or are insolvent or rendered insolvent by reason of our entry into such guaranty;

- were or are engaged in business or transactions for which the assets remaining with us constituted unreasonably small capital; or

- intended to incur or incurred, or believed or believe that we would incur, debts beyond our ability to pay such debts as they mature; and

- in each case, intended to receive or received less than reasonably equivalent value or fair consideration therefor,

then our obligations under the guaranty could be avoided, or claims with respect to that agreement could be subordinated to the claims of other creditors. Among other things, a legal challenge to the guaranty on fraudulent conveyance grounds may focus on the benefits, if any, realized by us as a result of PifCo's or PGF's issuance of these notes. To the extent that the guaranty is held to be a fraudulent conveyance or unenforceable for any other reason, the holders of the PifCo notes or the PGF notes would not have a claim against us under the relevant guaranty and will solely have a claim against PifCo or PGF. We cannot assure you that, after providing for all prior claims, there will be sufficient assets to satisfy the claims of the PifCo noteholders or the PGF noteholders relating to any avoided portion of the guaranty.

Holders in some jurisdictions may not receive payment of gross-up amounts for withholding in compliance with the European Council Directive on taxation of savings income.

Austria and Luxembourg have opted out of certain provisions of the European Council Directive regarding taxation of savings income (Directive) and are instead, during a transitional period, applying a withholding tax on payments of interest, at a rate of up to 35%, unless the holder opts for exchange of information as required under the Directive. Neither we nor the paying agent (nor any other person) would be required to pay additional amounts in respect of the notes as a result of the imposition of withholding tax by any member state of the European Union (Member State) or another country or territory which has opted for a withholding system. For more information, see “Taxation—Taxation Relating to PifCo’s and PGF’s Notes—European Union Tax Considerations.” An investor should consult a tax adviser to determine the tax consequences of holding the notes for such investor.

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Item 4. Information on the Company

History and Development

Petróleo Brasileiro S.A.—Petrobras—was incorporated in 1953 to conduct the Brazilian federal government's hydrocarbon activities. We began operations in 1954 and have been carrying out crude oil and natural gas production and refining activities in Brazil on behalf of the government. As of December 31, 2012, the Brazilian federal government owned 28.67% of our outstanding capital stock and 50.26% of our voting shares. Our common and preferred shares have been traded on the BM&FBOVESPA since 1968 and on the NYSE since 2000.

As part of a comprehensive reform of the oil and gas regulatory system, the Brazilian Congress amended the Brazilian Constitution in 1995 to authorize the Brazilian federal government to contract with any state or privately-owned company to carry out upstream, oil refining, cross-border commercialization and transportation activities in Brazil of oil, natural gas and their respective products. On August 6, 1997, Brazil enacted Law No. 9,478, which established a concession-based regulatory framework, ended our exclusive right to carry out oil and gas activities, and allowed competition in all aspects of the oil and gas industry in Brazil. Law No. 9,478 also created an independent regulatory agency, the ANP, to regulate the oil, natural gas and renewable fuel industry in Brazil and to create a competitive environment in the oil and gas sector. See "Regulation of the Oil and Gas Industry in Brazil—Price Regulation**."**

In 2010, new laws were enacted to regulate exploration and production activities in pre-salt areas not subject to existing concessions. Pursuant to this new legislation, we entered into an agreement with the Brazilian federal government on September 3, 2010, or Assignment Agreement, under which the government assigned to us the right to activities for the exploration and production of oil, natural gas and other fluid hydrocarbons in specified pre-salt areas, subject to a maximum production of five bnbbl of oil equivalent. The initial purchase price for our rights under the Assignment Agreement was R$74,807,616,407, which was equivalent to U.S.$42,533,327,500 as of September 1, 2010. On September 29, 2010, we issued new shares (including shares in the form of ADSs) in a global public offering consisting of a registered offering in Brazil and an international offering that included a registered offering in the United States. We applied part of the net proceeds from the global offering to pay the initial purchase price under the Assignment Agreement.

We operate through subsidiaries, joint ventures, and associated companies established in Brazil and many other countries. Our principal executive office is located at Avenida República do Chile 65, 20031-912 Rio de Janeiro, RJ, Brazil and our telephone number is (55-21) 3224-4477.

Overview of the Group

We are an integrated oil and gas company that is the largest corporation in Brazil and one of the largest companies in Latin America in terms of revenues. As a result of our legacy as Brazil's former sole supplier of crude oil and oil products and our ongoing commitment to development and growth, we operate most of Brazil's producing oil and gas fields and hold a large base of proved reserves and a fully developed operational infrastructure. In 2012, our average domestic daily oil production was 1,980 mbbl/d, an estimated 96.1% of Brazil's total. Over 73.5% of our domestic proved reserves are in large, contiguous and highly productive fields in the offshore Campos Basin, which allows us to optimize our infrastructure and limit our costs of exploration, development and production. In 44 years of developing Brazil's offshore basins we have developed special expertise in deepwater exploration and production, which we exploit both in Brazil and in other offshore oil provinces.

As of December 31, 2012, we had proved developed oil and gas reserves of 7,543.3 mmboe and proved undeveloped reserves of 4,730.6 mmboe in Brazil. The exploration and development of this large reserve base and the new pre-salt areas granted to us by the Brazilian federal government under the Assignment Agreement has demanded, and will continue to demand, significant investments and the rapid growth of our operations. To support this growth, we have ordered the construction of 22 new FPSOs and 28 drilling rigs and are also making necessary investments in infrastructure.

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We operate substantially all of the refining capacity in Brazil. Most of our refineries are located in Southeastern Brazil, within the country's most populated and industrialized markets and adjacent to the Campos Basin that provides most of our crude oil. Our domestic refining capacity of 2,018 mbbl/d is well balanced with our domestic refining throughput of 1,997 mbbl/d and sales of oil products to domestic markets of 2,285 mbbl/d. We are also involved in the production of petrochemicals. We distribute oil products through our own retail network and to wholesalers.

We participate in most aspects of the Brazilian natural gas market. We expect the percentage of natural gas in Brazil's energy matrix to grow in the future as a result of the expansion of Brazil's gas transportation infrastructure which began in 2005 and was largely completed in 2011 and as we expand our production of both associated and non-associated gas, mainly from offshore fields in the Campos, Espírito Santo and Santos Basins. We import natural gas from Bolivia and use LNG terminals to meet demand and diversify our supply. We also participate in the domestic power market primarily through our investments in gas-fired thermoelectric power plants. In addition, we participate in the fertilizer business, which is another important source of natural gas demand.

Outside of Brazil, we operate in 21 countries. In South America, our operations extend from exploration and production to refining, marketing, retail services and natural gas pipelines. In North America, we produce oil and gas and have refining operations in the United States. In Africa, we produce oil in Angola and Nigeria, and in Asia, we have refining operations in Japan. In other countries, we are engaged mainly in oil and gas exploration.

Comprehensive information and tables on reserves and production is presented at the end of Item 4. See "—Additional Reserves and Production Information."

Our activities comprise six business segments:

- **Exploration and Production**: oil and gas exploration, development and production in Brazil;

- **Refining, Transportation and Marketing**: includes refining, logistics, transportation, trading operations, oil products and crude oil exports and imports, as well as petrochemical sector in Brazil;

- **Distribution**: distribution of oil products, ethanol and vehicle natural gas to wholesalers and through our "BR" retail network in Brazil;

- **Gas and Power**: transportation and trading of natural gas and LNG, as well as generation and trading of electric power and the fertilizer business;

- **Biofuel**: production of biodiesel and its co-products and ethanol-related activities such as equity investments, production and trading of ethanol, sugar and the excess electric power generated from sugarcane bagasse; and

- **International**: exploration and production of oil and gas, refining, transportation and marketing, distribution and gas and power operations, outside of Brazil.

Our Corporate segment comprises activities that cannot be attributed to the other segments, notably those related to corporate financial management, corporate overhead and other expenses, including actuarial expenses related to the pension and medical benefits for retired employees and their dependents.

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The following table sets forth key information for each business segment in 2012:

Key Information by Business Segment, 2012

	Exploration and Production	Refining, Transportation and Marketing	Gas and Power	Biofuel	Distribution	International	Corporate	Eli
					(U.S.$ million)			
	74,714	116,710	11,803	455	40,712	17,929	–	
e income taxes	35,465	(17,699)	1,277	(156)	1,386	1,933	(6,999)	
ember 31	151,798	91,458	28,454	1,248	8,130	18,735	39,125	
s and investments	21,959	14,745	2,113	147	666	2,572	747	

Exploration and Production

Exploration and Production Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Exploration and Production:			
Sales revenues	74,714	74,117	54,273
Income (loss) before income taxes	35,465	36,809	25,439
Total assets at December 31	151,798	141,113	136,600
Capital expenditures and investments	21,959	20,405	18,621

Oil and gas exploration and production activities in Brazil are the largest component of our portfolio. We have gradually increased production over the past four decades, from 164 mbbl/d of crude oil, condensate and natural gas liquids in Brazil in 1970 to 1,980 mbbl/d in 2012. We aim to grow oil and gas reserves and production sustainably and be recognized for excellence in Exploration and Production operations.

The primary focus of our E&P segment is to:

- Continue to explore and develop the Campos Basin, leveraging the current infrastructure to drill in deeper horizons in existing concessions, including pre-salt reservoirs;

- Explore and develop Brazil’s two other most promising offshore basins, Espírito Santo (light oil, heavy oil and gas) and Santos (gas and light oil), with a particular focus on pre-salt development;

- Employ new technologies for secondary recovery and increase production efficiency of our older offshore fields and production systems, as well as sustain and increase production from onshore and shallow fields through drilling and enhanced recovery operations;

- Explore light oil and natural gas in new frontiers, including Brazil's equatorial and eastern margins; and

- Develop associated and non-associated gas resources in the Santos Basin and elsewhere (including continued reductions in gas flaring) to meet Brazil's growing demand for gas and to increase the contribution of Brazilian gas production as a proportion of total domestic gas supply.

Brazil's richest oil fields are located offshore, most of them in deep waters. Since 1971, when we started exploration in the Campos Basin, we have been active in these waters and we have become globally recognized as innovators in the technology required to explore and produce hydrocarbons in deep and ultra-deep water. According to production data from PFC Energy, we operate more production (on a boe basis) from fields in deep and ultra-deep water than any other company. We focus much of our exploration effort on deep water drilling, where the discoveries are substantially larger and our technology and expertise create a competitive advantage.

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In 2012, offshore production accounted for 89% of our production and deep water production accounted for 78% of our production in Brazil. In 2012, we drilled 45 exploratory wells and operated 42 wells in water deeper than 1,000 meters (3,281 feet).

Offshore exploration, development and production costs are generally higher than those onshore, but we have been able to offset these higher costs by higher drilling success ratios, larger discoveries and greater production volumes. We have historically been successful in finding and developing significant oil reservoirs offshore, which has allowed us to achieve economies of scale by spreading the total costs of exploration, development and production over a large base. By focusing on opportunities that are close to existing production infrastructure, we limit the incremental capital requirements of new field development.

Historically, our offshore exploration and production activities were focused on post-salt reservoirs. In recent years, we have focused our offshore exploration efforts on pre-salt reservoirs located in a region of approximately 149,000 km^2 (36.8 million acres) stretching from the Campos to the Santos Basins, also known as the pre-salt province. Our existing contracts in this area cover 26.6% (approximately 39,615 km^2 or 9.8 million acres) of the pre-salt areas, including the pre-salt areas assigned to us under Concession Contracts and the Assignment Agreement. An additional 4% (approximately 6,000 km^2 or 1.5 million acres) is under concession to other oil companies for exploration. The remaining 69.4% (approximately 103,000 km^2 or 25.4 million acres) of the pre-salt area is open acreage area, not licensed yet, and the licensing of new pre-salt areas will be made under a production-sharing regime under Law No. 12,351, enacted on December 22, 2010.

We hold interests ranging from 20% to 100% in the pre-salt exploration areas under concession to us. In the southern part of the Santos Basin, where the salt layer is thick and the hydrocarbons have been more perfectly preserved, we have made several particularly promising discoveries since 2006, including those made in Blocks BM-S-11 (Iara and Lula, formerly Tupi), BM-S-9 (Carioca and Sapinhoá, formerly Guará) and since 2011 in the Assignment Agreement area (Franco, Nordeste de Tupi). In the northern part of the region, we made significant discoveries in 2008 and early 2010 in the area known as Parque das Baleias and in the Barracuda, Albacora, Marlim and Caratinga fields, all of which are in the Campos Basin. As a result, we are committing substantial resources to develop these pre-salt discoveries, which are located in deep and ultra-deep waters and reservoirs at total depths of up to 7,000 meters (22,965 feet).

As of December 31, 2012, we had 117 exploration agreements covering 168 blocks, corresponding to a gross exploratory acreage of 90,708 km^2 (22 million acres), or a net exploratory acreage of 76,427 km^2 (19 million acres), and 52 evaluation plans. We are exclusively responsible for conducting the exploration activities in 31 of the 117 exploration agreements. As of December 31, 2012, we had exploration partnerships with 22 foreign and domestic companies. We conduct exploration activities under 47 of our 117 partnership agreements.

In 2012, we invested a total of U.S.$5.97 billion in exploration activities in Brazil. We drilled a total of 137 exploratory wells in 2012, of which 57 were offshore and 80 onshore. Our 2013-2017 Business and Management Plan, which was released on March 15, 2013, foresees capital expenditures and investments in exploration and production activities in Brazil of U.S.$147.5 billion from 2013 to 2017 (not including investments by our partners).

During 2012, our oil and gas production from Brazil averaged 2,205.5 mboe/d, of which 90% was oil and 10% was natural gas. On December 31, 2012, our estimated net proved crude oil and natural gas reserves in Brazil were 12.3 billion boe, of which 85.9% was crude oil and 14.1% was natural gas. Brazil provided 90.4% of our worldwide production in 2012 and accounted for 95.2% of our worldwide reserves at December 31, 2012 on a barrels of oil equivalent basis. Historically, approximately 85% of our total Brazilian production has been oil.

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We have also implemented a variety of programs designed to increase oil recovery from existing fields, reduce natural declines from producing fields and also reduce operational costs. During 2012 we implemented two important programs: PROEF which aims to increase the operational efficiency within the Campos Basin, returning production efficiency to the basins' historical levels and PROCOP to optimize operating costs and productivity.

Our exploration and production activities outside Brazil are included in our International business segment. See "—International."

We have historically conducted exploration, development and production activities in Brazil through concession contracts, which we have obtained through participation in bid rounds conducted by the ANP. Some of our existing concessions were granted by the ANP without an auction in 1998, as provided by Law No. 9,478. These are known as the "Round Zero" concession contracts. Since such time, we have participated in all of the auction rounds conducted by ANP and intend to participate in the upcoming 11th bidding round on May 14 and 15, 2013.

The following map shows our concession areas in Brazil as of December 2012.

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The map below shows the location of the pre-salt reservoirs as well as the status of our exploratory activities there.

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Information about our principal oil and gas producing fields in Brazil is summarized in the table below.

Principal Oil and Gas Producing Fields in Brazil

Basin	**Fields**	**Petrobras %**	**Type**	**Fluid**(1)
Camamu	Manati	35%	Shallow	Natural Gas
Campos	Albacora	100%	Shallow	Intermediate Oil
			Deepwater	Intermediate Oil
	Albacora Leste	90%	Deepwater	Intermediate Oil
			Ultra-deepwater	
	Baleia Azul	100%	Deepwater	Intermediate Oil
	Barracuda	100%	Deepwater	Intermediate Oil
	Cachalote	100%	Deepwater	Intermediate Oil
	Carapeba	100%	Shallow	Intermediate Oil
	Caratinga	100%	Deepwater	Intermediate Oil
	Cherne	100%	Shallow	Intermediate Oil
	Espadarte	100%	Deepwater	Intermediate Oil
	Jubarte	100%	Deepwater	Heavy Oil
	Marimbá	100%	Deepwater	Heavy Oil
	Marlim	100%	Deepwater	Heavy Oil
	Marlim Leste	100%	Deepwater	Intermediate Oil
	Marlim Sul	100%	Deepwater	Intermediate Oil
			Ultra-deepwater	
	Namorado	100%	Shallow	Intermediate Oil
	Pampo	100%	Shallow	Intermediate Oil
	Roncador	100%	Ultra-deepwater	Intermediate Oil
	Tartaruga Mestiça	100%	Shallow	Intermediate Oil
	Vermelho	100%	Shallow	Intermediate Oil
	Voador	100%	Deepwater	Heavy Oil
Espírito Santo	Fazenda Alegre	100%	Onshore	Heavy Oil
	Golfinho	100%	Deepwater	Intermediate Oil
			Ultra-deepwater	Intermediate Oil
Potiguar	Canto do Amaro	100%	Onshore	Intermediate Oil/Natural Gas
				Heavy Oil/Natural Gas
	Estreito	100%	Onshore	Heavy Oil
Recôncavo	Aracas	100%	Onshore	Light Oil
	Buaracica	100%	Onshore	Light Oil
Santos	Baúna	100%	Shallow	Light Oil
	Mexilhão	100%	Shallow	Natural Gas
	Lula	65%	Ultra-deepwater	Intermediate Oil
	Piracaba	100%	Shallow	Light Oil

	Uruguá	100%	Deepwater	Intermediate Oil/Natural Gas
Sergipe/Alagoas	Carmópolis	100%	Onshore	Intermediate Oil
	Piranema	100%	Deepwater	Intermediate Oil
Solimões	Leste do Urucu	100%	Onshore	Light Oil/Natural Gas
	Rio Urucu	100%	Onshore	Light Oil/Natural Gas

(1) Heavy oil = up to 22° API; intermediate oil = 22° API to 31° API; light oil = greater than 31° API

Our domestic oil and gas exploration and production efforts are primarily focused on four major basins offshore in Brazil: Campos, Espírito Santo, Santos and Sergipe-Alagoas.

Campos Basin

The Campos Basin, which covers approximately 115,000 km^2 (28.4 million acres), is the most prolific oil and gas basin in Brazil as measured by proved hydrocarbon reserves and annual production. Since we began exploring this area in 1971, over 60 hydrocarbon accumulations have been discovered, including eight large oil fields in deep water and ultra-deep water.

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As of December 31, 2012, we held rights to 21 exploratory blocks (6 are evaluation plans) in the Campos Basin, comprising a total of 7,649 km^2 (1.89 million acres). During 2012, we have made important progress in the Campos Basin, where we have drilled a total of 17 wells (6 of them in the pre-salt reservoirs). Of particular note are the discoveries in the Parque das Baleias area, in the northern part of Campos Basin off the coast of the State of Espírito Santo.

The Campos Basin is our largest oil- and gas-producing region, producing an average 1,618.3 mbbl/d of oil and 498.5 mmcf/d (13.2 mmm^3/d) of associated natural gas from 45 producing fields. During 2012, 77.0% of our total domestic production came from this Basin. The proved crude oil and natural gas reserves in the Campos Basin represented, in 2012, respectively, 77.8% and 47.5% of our total proved crude oil and natural gas reserves in Brazil.

We operated 41 floating production systems and 14 fixed platforms in water depths from 80 to 1,886 meters (262 to 6,188 feet), delivering oil with an average API gravity of 22.9° and a maximum basic sediment and water (a measurement of the water and sediment content of flowing crude oil) of 1%.

Production growth in the Campos Basin originates mainly from the installation of new platforms to develop our proved reserves in the region. The connection of new wells to previously installed platforms also contributed significantly to production increases in the Campos Basin. The interconnection of new wells in the P-48, P-56 and P-57 platforms and the FPSO-Cidade de Angra dos Reis added 174.8 mbbl/d to our average production in the Campos Basin in 2012.

While most of our production in the Campos Basis is from post-salt reservoirs, pre-salt reservoirs in the Campos Basin are a growing source of production. We first began producing pre-salt oil production in 2008 from the Jubarte field located in the region known as Parque das Baleias. We subsequently began producing from the Baleia Franca field in the second half of 2010. In September 2012, we started a pilot system exclusively dedicated to pre-salt appraisal and production in the Baleia Azul region using the FPSO Cidade de Anchieta, with a capacity to produce 100,000 bbl/d of oil and 123.6 mmcf/d (3.5 mmm^3/d) of gas. As of the year end 2012, the Campos Basin pre-salt area was producing 82.7 mbbl/d, which is expected to increase due to additional discoveries that have been made in other existing concessions.

Campos Basin Projects

We are currently developing five major projects in the Campos Basin: Roncador Modules 3 and 4, Papa-Terra Modules 1 and 2, and Parque das Baleias (Baleia Azul, Jubarte, Cachalote, Baleia Anã and Baleia Franca).

Main Campos Basin Development Projects

Field	Unit Type	Production Unit	Crude Oil Nominal Capacity (bbl/d)	Natural Gas Nominal Capacity (mmcf/d)	Water Depth (meters)	Start Up (year)	Notes
Papa-Terra–Module 1	TLWP	P-61	0	0	1,180	2013	Production by P-63 Post-salt
Papa-Terra–Module 2	FPSO	P-63	140,000	35.3	1,170	2013	Post-salt
Roncador–Module 3	SS	P-55	180,000	211.9	1,790	2013	Post-salt
Roncador–Module 4	FPSO	P-62	180,000	211.9	1,550	2014	Post-Salt
Baleia Azul, Jubarte, Cachalote, Baleia Anã & Baleia Franca	FPSO	P-58	180,000	211.9	1,400	2014	Pre-salt

The aim of Papa-Terra project is to develop the production of Papa-Terra field located in the post-salt of Campos Basin. Petrobras will install during 2013 two stationary production units, namely: P-61 (which is a TLWP) and P-63 (which is a FPSO). The joint production capacity of P-61 and P-63 is of 140,000 bbl/d of oil and 35.3 mmcf/d (1 mmm^3/d) of natural gas. The TLWP will be supported by a TAD (Tender Assisted Drilling) rig and its production will be transferred to the FPSO.

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Roncador Module 3 and 4 will develop the production of Roncador Field, located in the post-salt of Campos Basin, through the installation of a stationary production unit (P-55, which is a SS) and a FPSO (P-62). The production capacity of each production unit is of 180,000 bbl/d of oil and 211.9 mmcf/d (6 mmm^3/d) of natural gas.

The production unit P-58 will develop production in the Parque das Baleias area, which encompasses the following fields: Baleia Franca (pre and post-salt), Cachalote (post-salt), Jubarte (pre and post-salt), Baleia Azul (pre-salt) and Baleia Anã (post-salt). This FPSO has an oil production capacity of 180,000 bbl/d and 211.9 mmcf/d (6 mmm^3/d) of natural gas.

Santos Basin

The Santos Basin, which covers approximately 348,900 km^2 (86 million acres) off the city of Santos, in the State of São Paulo, is one of the most promising exploration and production areas offshore Brazil. As of December 31, 2012, we held exploration rights to 26 blocks in the Santos Basin, comprising 13,580 km2 (3.4 million acres).

The Santos Basin pre-salt was a central focus of E&P activities in 2012. In this period we have drilled 15 wells (13 in the pre salt area) in total. We continue to concentrate our efforts on gathering information about the pre-salt reserves through EWTs and testing drilling technologies to improve efficiency and to plan the definitive design of production platforms.

During 2012, we made several light oil discoveries within the areas of Franco, Carioca, Tupi NE, Bem-te-vi, BM-S-42, Iara, South of Guará and Júpiter NE. All of these discoveries were in the pre salt reservoir, with exception of Júpiter NE which was in the post salt.

In the Santos Basin in 2012, our share of average daily production of oil was 98.6 mbbl/d, of which 55.7 mbbl/d was produced in the pre-salt area and our average daily production of natural gas was 296.8 mmcf/d (7.9 mmm^3/d), of which was 57 mmcf/d (1.5 mmm^3/d) was produced in the pre-salt area. In the Santos Basin, we held proved crude oil and natural gas reserves representing, in 2012, respectively 14.1% and 24.7% of our total proved crude oil and natural gas reserves in Brazil.

The first productive field in the Santos Basin pre-salt was Lula (formerly Tupi), which began producing oil in May 2009 following an 18-month EWT. In November 2010, we replaced the EWT with a long-term production system, the FPSO Cidade de Angra dos Reis. During 2012, the FPSO produced near oil production capacity of 100 mbbl/d. We drilled two wells to be interconnected in 2013, one of which was the first horizontal well drilled in the complex geological conditions of the pre-salt. We currently have two systems performing EWT's in the Santos Basin pre-salt, the FPSO Cidade de São Vicente and the FPSO Dynamic Producer.

Under the Assignment Agreement, we acquired six blocks and one contingent block which comprise our rights to explore, evaluate and produce up to five bnbbl of oil equivalent in the pre-salt area of the Santos Basin. We are developing these blocks in an integrated manner with the pre-salt areas we already have under concession. See Item 10. "Material Contracts—Assignment Agreement."

In 2012, we concluded the drilling of four wells located in the Assignment Agreement area (Franco NW, Franco SW, Nordeste de Tupi and Sul de Guara). The FPSO Dynamic Producer will start operating Franco EWT, the first EWT under the Assignment Agreement area, which is planned to become effective in the second quarter of 2013. Over the next three years, we will proceed with our exploration program and are currently targeting the production of oil in the Franco area in 2016.

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Santos Basin Projects

The source of future production from the Santos Basin will be predominantly from deep and ultra-deep water oil fields. We will be developing, until 2016, 13 major projects in the Santos Basin. Of these, 2 are in the Assignment Agreement area (Franco 1 and Franco 2). These FPSOs are currently being constructed under contracts. The next phase, beginning in 2017, will include the application of improved technologies and engineering specifically designed for the pre-salt fields.

Field	Unit Type	Production Unit	Crude Oil Nominal Capacity (bbl/d)	Natural Gas Nominal Capacity (mmcf/d)	Water Depth (meters)	Start Up (year)	Notes
Bauna & Piracaba (BM-S-40)	FPSO	Cidade de Itajai	80,000	70.6	200	2013	Post-salt
Sapinhoá Pilot (Guará)	FPSO	Cidade de São Paulo	120,000	176.6	2,141	2013	Pre-salt
Lula (Northeast) Pilot	FPSO	Cidade de Paraty	120,000	176.6	2,200	2013	Pre-salt
Sapinhoá (North)	FPSO	Cidade de Ilha Bela	150,000	211.9	2,100	2014	Pre-salt
racema (South)	FPSO	Cidade de Mangaratiba	150,000	282.5	2,100	2014	Pre-salt
racema (North)	FPSO	Cidade de Itaguaí (Z1)	150,000	282.5	2,100	2015	Pre-salt
Lula (High)	FPSO	P-66	150,000	247.2	2,100	2016	Pre-salt
Lula (Central)	FPSO	P-67	150,000	176.6	2,100	2016	Pre-salt
Lula (South)	FPSO	P-68	150,000	221.9	2,100	2016	Pre-salt
Franco 1 Assignment Agreement	FPSO	P-74	150,000	247.2	2,100	2016	Assignment Agreement
Carioca	FPSO	No name (Z2)	80,000	152.4	2,100	2016	Pre-salt
Lula (North)	FPSO	P-69	150,000	211.9	2,100	2016	Pre-salt
Franco 2 Assignment Agreement	FPSO	P-75	150,000	247.2	2,100	2016	Assignment Agreement

Following Lula, the second field to begin development in the Santos pre-salt will be Sapinhoá (formerly known as Guará) which is one of the largest oil fields in Brazil, with a total estimated recoverable volume of 2.1 billion boe. Commercial production began in January 2013 through FPSO Cidade de Sao Paulo four years from discovery. The pilot system has a production capacity of 120,000 bbl/d of oil and natural gas processing of 176.6 mmcf/d (5 mmm^3/d). The first well drilled by Cidade de Sao Paulo is capable of producing over 25,000 bbl/d of oil.

The Sapinhoá field Development Plan comprises two permanent systems. The next FPSO to be installed will be the FPSO Cidade de Ilhabela with a production capacity of 150,000 bbl/d of oil and 211.9 mmcf/d (6 mmm^3/d) of gas. This FPSO is currently under construction and expected to begin operations during the second half of 2014.

The third pilot system for the Santos pre-salt will be Lula Northeast, through FPSO Cidade de Paraty. Production is scheduled to begin in May 2013. This FPSO has a capacity of 120,000 bbl/d of oil and 176.6mmcf/d (5 mmm^3/d) of natural gas processing.

We are also developing post-salt fields in the Santos Basin. The FPSO Cidade de Itajaí in Baúna (formerly Tiro and Sidon) began operating in February, 2013. This FPSO has a capacity to process up to 80,000 bbl/d of oil and 70.6 mmcf/d (2 mmm^3/d) of natural gas.

Espírito Santo Basin

We have made several discoveries of light oil and natural gas in the Espírito Santo Basin, which covers approximately 75,000 km^2 (18.5 million acres) offshore and 14,000 km^2 (3.5 million acres) onshore. During 2012 we made two discoveries within the Golfinho area, both of them in the post-salt region. On December 31, 2012, we held exploration rights to 16 blocks (4 are evaluation plans) comprising a total of 3,861 km^2 (1.0 million acres).

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At December 31, 2012, we were producing from 46 producing fields oil at an average rate of 43.8 mbbl/d and our average daily production of natural gas was of 215.1 mmcf/d (5.7 mmm^3/d). At December 31, 2012, we held proved crude oil and natural gas reserves representing respectively, 0.7% and 4.8% of our total proved oil and natural gas reserves in Brazil.

In addition to developing new production projects, we are also optimizing existing resources in the Espírito Santo area by constructing the Sul Norte Capixaba gas pipeline with capacity to transport 247.2 mmcf/d (7 mmm^3/d). The pipeline, which runs from the Parque das Baleias area to the Cacimbas gas treatment unit, came online in November 2012.

Sergipe/Alagoas Basin

The Sergipe-Alagoas Basin is one of our new frontier offshore regions. During 2012, we made 5 new discoveries in the areas informally denominated as Muriú, Moita Bonita, Farfan, Cumbe and Barra-1. All of them are in ultra-deep water, in a distance of almost 100 km from Aracaju. As of December 31, 2012, we held exploration rights to 11 blocks in the Sergipe-Alagoas Basin, comprising 3,297 km2 (0.81 million acres). Our aggregate production level in Sergipe–Alagoas Basin was of 48.9 mbbl/d of oil and 66.4 mmcf/d (1.8 mmm^3/d) of natural gas. In the Sergipe/Alagoas Basin, we held proved crude oil and natural gas reserves representing, in 2012, respectively 1.84% and 2.48% of our total proved crude oil and natural gas reserves in Brazil.

Other Basins

We produce hydrocarbons and hold exploration acreage in 19 other basins in Brazil. Of these, the most significant are the shallow offshore Camamu Basin and the onshore Potiguar, Recôncavo and Solimões Basins. While our onshore production is primarily in mature fields, we plan to sustain and slightly increase production from these fields in the future by using enhanced recovery methods. In 2012, these other basins production was of 167.5 mbbl/d of oil and 282 mmcf/d (7.5 mmm^3/d) of natural gas.

Critical Resources in Exploration and Production

We seek to develop and retain the critical resources that are necessary to meet our production targets. Drilling rigs are an important resource for our E&P operations and substantial lead time is required when fleet expansion is needed. When we discovered the pre-salt, in 2007 our activities were constrained by the availability of rigs, but our subsequent efforts to contract additional rigs has eliminated this constraint. Whereas in 2008 we only had three rigs capable of drilling in water depths greater than 2000 meters (6,560 feet), we had 40 as of December 31, 2012. We believe that we now have sufficient rigs to meet our long term production targets, although we will continue to evaluate our drilling requirements and will adjust our fleet size as needed.

In addition to contracting the additional rigs that are now operating in Brazil, all of which were built internationally, we have been working since 2008 to develop the capacity to construct drilling rigs in Brazil. We have awarded contracts for 28 additional rigs to be built in Brazil to meet our long-term needs and satisfy Brazilian local content requirements arising out of the Assignment Agreement and concession agreements obtained in later Brazilian exploration bid rounds. We expect these rigs to be delivered from 2015 through 2020 and they will replace or supplement the existing fleet in Brazil. The contracts to build the 28 rigs was awarded to Sete Brasil S.A. (Sete BR), a Brazilian company in which Petrobras holds a 10% interest.

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Drilling Units in Use by Exploration and Production on December 31 of Each Year

	2012		2011		2010	
	Leased	**Owned**	**Leased**	**Owned**	**Leased**	**Owned**
Onshore	24	11	17	11	22	12
Offshore, by water depth (WD)	65	9	54	8	44	8
Jack-up rigs	0	5	1	4	1	4
Floating rigs:	65	4	53	4	43	4
500 to 1000 meters WD	6	2	8	2	11	2
1001 to 2000 meters WD	19	2	26	2	19	2
2001 to 3000 meters WD	40	0	19	0	13	0

Refining, Transportation and Marketing

Refining, Transportation and Marketing Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Refining, Transportation and Marketing:			
Sales revenues	116,710	118,630	97,936
Income (loss) before income taxes	(17,699)	(8,753)	3,141
Total assets at December 31	91,458	84,330	70,515
Capital expenditures and investments	14,745	16,133	16,198

We are an integrated company with a dominant market share in our home market. We own and operate 12 refineries in Brazil, with a total net distillation capacity of 2,018 mbbl/d, and are one of the world’s largest refiners. As of December 31, 2012, we operated substantially all of Brazil’s total refining capacity. We supplied almost all of the refined product needs of third-party wholesalers, exporters and petrochemical companies, in addition to the needs of our Distribution segment. We operate a large and complex infrastructure of pipelines and terminals and a shipping fleet to transport oil products and crude oil to domestic and export markets. Most of our refineries are located near our crude oil pipelines, storage facilities, refined product pipelines and major petrochemical facilities, facilitating access to crude oil supplies and end-users.

We also import and export crude oil and oil products. The demand for oil products in Brazil is increasing rapidly, driven primarily by the economic growth and rising real incomes. Since 2010, we have met this incremental growth in demand primarily by increasing imports as our refining capacity was not sufficient to meet the increased demand. This growth in imports has increased our cost of sales, contributing to declining margins when we have not passed on the higher import costs of our domestic product prices. See Item 5. "Operating and Financial Review and Prospects."Additional refining capacity currently under construction will help to reduce our import needs, but we will continue to require product imports for the foreseeable future**.**

Our Refining, Transportation and Marketing segment also includes (i) petrochemical operations that add value to the hydrocarbons we produce and meet the needs of the growing Brazilian economy and (ii) extraction and processing of shale.

We participate in refining, transportation and marketing operations outside of Brazil through our International business segment. See "—International."

Refining

Our refining capacity in Brazil as of December 31, 2012, was 2,018 mbbl/d and our average throughput during 2012 was 1,944 mbbl/d.

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The following table shows the installed capacity of our Brazilian refineries as of December 31, 2012, and the average daily throughputs of our refineries in Brazil in 2012, 2011 and 2010.

Capacity and Average Throughput of Refineries

Name (Alternative Name)	Location	Crude Distillation Capacity at December 31, 2012 (mbbl/d)	Average Throughput 2012	2011 (mbbl/d)	2010
LUBNOR	Fortaleza (CE)	8	8	7	8
RECAP (Capuava)	Capuava (SP)	53	53	43	36
REDUC (Duque de Caxias)	Rio de Janeiro (RJ)	239	263	254	256
REFAP (Alberto Pasqualini)	Canoas (RS)	189	154	148	145
REGAP (Gabriel Passos)	Betim (MG)	151	145	129	143
REMAN (Isaac Sabbá)	Manaus (AM)	46	38	42	42
REPAR (Presidente Getúlio Vargas)	Araucária (PR)	195	199	193	170
REPLAN (Paulínia)	Paulinia (SP)	396	387	373	316
REVAP (Henrique Lage)	São Jose dos Campos (SP)	252	248	240	238
RLAM (Landulpho Alves)	Mataripe (BA)	281	239	233	250
RPBC (Presidente Bernardes)	Cubatão (SP)	172	172	166	160
RPCC (Potiguar Clara Camarão)	Guamaré (RN)	36	37	34	33
Total		2,018	1,944	1,862	1,798

In recent years, we have made substantial investments in our refinery system for the following purposes:

- Improve gasoline and diesel quality to comply with stricter environmental regulations;

- Increase crude slate flexibility to process more Brazilian crude, taking advantage of light/heavy crude price differentials;

- Increase residuum conversion; and

- Reduce the environmental impact of our refining operations.

In 2012, we invested a total of U.S.$3,435 million in our refineries, of which U.S.$2,581 million was invested for hydrotreating units to improve the quality of our diesel and gasoline and U.S.$419 million for coking units to convert heavy oil into lighter products.

The following refinery upgrades are underway for expected completion between 2013 and 2014:

- Diesel quality upgrades at REGAP, REFAP, REPLAN and RPBC; and

- Gasoline quality upgrades at REPLAN and RLAM.

The following refinery upgrade projects are scheduled for completion after 2014:

- Diesel quality upgrades at REDUC; and

- Upgrades to receive, process and deliver LPG and natural gas produced in the processing plant located in Caraguatatuba in the State of São Paulo.

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By the end of 2013, all of our refineries will be capable of producing a maximum sulfur content for diesel of 500 ppm, and six of our refineries (RLAM, REGAP, REPLAN, RECAP, REVAP and REPAR) are expected to have capacity to produce 10 ppm sulfur diesel. By 2014, we will also reduce the maximum sulfur content of the gasoline produced in our refineries from 1,000 ppm to 50 ppm.

Major Refinery Projects

Brazil has one of the highest rates of demand growth in the world for transportation fuels, particularly gasoline, diesel and jet fuel. We are planning capacity expansions to meet the needs of this growing market and add value to our growing volumes of crude oil production in Brazil. We are currently building two new refining facilities:

- Complexo Petroquímico do Rio de Janeiro—Comperj, an integrated refining and petrochemical complex. We broke ground in 2008, and began construction in 2010. The 165 mbbl/d refining operation is scheduled to start up in 2015; and

- Abreu e Lima, a refinery in Northeastern Brazil is designed to process 230 mbbl/d of crude oil to produce 162 mbbl/d of low sulfur diesel (10 ppm) as well as LPG, naphtha, bunker fuel and petroleum coke. We expect operations to come on stream in 2014.

We are also in the evaluation stage for two new refineries in Northeastern Brazil:

- Premium I in the State of Maranhão is designed to process 20° API heavy crude oil, maximize production of low sulfur diesel, and produce LPG, naphtha, low sulfur kerosene, bunker fuel and petroleum coke. This refinery will be built in two phases of 300 mbbl/d each; and

- Premium II in the State of Ceará will have a processing capacity of 300 mbbl/d and will follow the same specifications as Premium I. The Premium facilities will be able to reduce costs and achieve efficiencies through simplification and standardization of the projects.

The following tables summarize output of oil products and sales by product in Brazil for the last three years.

Domestic Output of Oil Products: Refining and marketing operations, mbbl/d(3)

	2012	**2011**	**2010**
Diesel	782	745	716
Gasoline	438	395	351
Fuel oil	238	234	243
Naphtha	106	109	133
LPG	143	137	132
Jet fuel	93	93	80

Other	196	183	177
Total domestic output of oil products	**1,997**	**1,896**	**1,832**
Installed capacity	2,018	2,013	2,007
Utilization (%)	96	92	90
Domestic crude oil as % of total feedstock processed	**82**	**82**	**82**

(1) Unaudited.

(2) As registered by the ANP.

(3) Output volumes are larger than throughput volumes as a result of gains during the refining process

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Domestic Sales Volumes, mbbl/d

	2012	**2011**	**2010**
Diesel	937	880	809
Gasoline	570	489	394
Fuel oil	84	82	100
Naphtha	165	167	167
LPG	224	224	218
Jet fuel	106	101	90
Other	199	188	180
Total oil products	**2,285**	**2,131**	**1,958**
Ethanol and other products	83	86	99
Natural gas	357	304	312
Total domestic market	**2,725**	**2,521**	**2,369**
Exports	554	633	698
International sales and other operations	506	563	581
Total international market	**1,060**	**1,196**	**1,279**
Total sales volumes	**3,785**	**3,717**	**3,648**

Delivery Commitments

We sell crude oil through long-term and spot-market contracts. Our long-term contracts specify the delivery of fixed and determinable quantities, subject to a price negotiation with third parties on a delivery-by-delivery basis. We are committed through long-term contracts to deliver a total of approximately 260 mbbl/d in 2013. We believe our domestic proved reserves will be sufficient to allow us to continue to deliver all contracted volumes. For 2013, approximately 84% of our exported crude oil will be committed to meeting our contractual delivery commitments to third parties.

Imports and Exports

Much of the crude oil we produce in Brazil is heavy or intermediate. We must import some light crude to balance the slate for our refineries, which were originally designed to run on lighter imported crude, and export heavier crude that we don’t have the capacity to process. We use exports and imports of crude oil to balance our domestic production and refinery capacity with market needs, while optimizing our refining margins.

Our imports and exports of oil products depend on our refinery output and Brazilian demand levels. We import oil products to balance any shortfall between production from our Brazilian refineries and the market demand for each product. We export oil product that our refineries produce in excess of Brazilian market demand, which is largely fuel oil. The table below shows our exports and imports of crude oil and oil products in 2012, 2011 and 2010:

Exports and Imports of Crude Oil and Oil Products, mbbl/d

	2012	2011	2010
Exports			
Crude oil	364	428	497
Fuel oil (including bunker fuel)	153	160	153
Gasoline	1	5	14
Other	30	38	33
Total exports	548	631	697
Imports			
Crude oil	346	362	316
Diesel and other distillates	190	199	177
LPG	53	61	58
Gasoline	87	43	9
Naphtha	58	64	42
Other	45	20	13
Total imports	779	749	615

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Logistics and Infrastructure for oil and oil products

We own and operate an extensive network of crude oil and oil products pipelines in Brazil that connect our terminals, refineries and other primary distribution points. On December 31, 2012, our onshore and offshore, crude oil and oil products pipelines extended 16,333 km (10,151 miles). We operate 28 marine storage terminals and 20 other tank farms with nominal aggregate storage capacity of 65 mmbbl. Our marine terminals handle an average 10,820 tankers and oil barges annually. We are working in partnership with other companies to develop and expand Brazil's ethanol pipeline and logistics network.

We operate a fleet of owned and chartered vessels. These provide shuttle services between our producing basins offshore Brazil and the Brazilian mainland, and shipping to other parts of South America and internationally. The fleet includes double-hulled vessels, which operate internationally where required, and single-hulled vessels, which operate in South America and Africa only. We are increasing our fleet of owned vessels to replace older vessels, decrease our dependency on chartered vessels and exposure to charter rates tied to the U.S. dollar, and accommodate growing production volumes. Upgrades will include replacing single-hulled tankers with double-hulled vessels and replacing vessels nearing the end of their 25-year useful life. Our long-term strategy continues to focus on the flexibility afforded by operating a combination of owned and chartered vessels.

Two new oil tankers were delivered to Transpetro on May 14, 2012 and June 18, 2012. The remaining orders for 46 vessels are scheduled to be delivered between 2013 and 2020, all of which will be built in Brazilian shipyards. In addition, Transpetro has contracted 20 convoys (each composed of four barges and one pushboat) for ethanol transportation on the Tietê-Paraná river waterway.

The table below shows our operating fleet and vessels under contract as of December 31, 2012.

Owned and Chartered Vessels in Operation and Under Construction Contracts at December 31, 2012

	In Operation		Under Contract/Construction	
	Number	Tons Deadweight Capacity	Number	Tons Deadweight Capacity
Owned fleet:				
Tankers	51	3,735,438	38	3,642,330
LPG tankers	6	40,171	8	42,000
Anchor Handling Tug Supply (AHTS)	1	2,163	–	–

Floating, Storage and Offloading (FSO)	1	28,903	–	–
Layed-up vessel	1	91,902	–	–
Total	**60**	**3,898,577**	**46**	**3,684,330**
Chartered vessels:				
Tankers	166	15,552,167	–	–
LPG tankers	11	232,014	–	–
Total	**177**	**15,784,181**	**–**	**–**

Petrochemicals

Our petrochemicals operations provide an outlet for our growing production volumes of gas and other refined products, which increase their value and provides substitute for products that are otherwise imported. Our strategy is to increase domestic production of basic petrochemicals and engage in second generation and biopolymer activities through investments in companies in Brazil and abroad, capturing synergies within all our businesses.

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We engage in our petrochemicals operations through the following subsidiaries, controlled entities and affiliated companies:

	mmt/y	Petrobras interest (%)
Braskem (1):		
Ethylene	3.95	
Polyethylene	3.03	36.20
Polypropylene	3.95	
PVC	0.71	
DETEN Química S.A.:		
LAB(1)	0.22	27.88
LABSA(1)	0.08	
METANOR S.A./COPENOR S.A.:		
Methanol	0.08	
Formaldehyde	0.09	34.54
Hexamine	0.01	
FCC Fábrica Carioca de Catalisadores S.A.:		
Catalysts	0.04	50.00
Additives	0.01	
INNOVA S.A.:		
Ethylbenzene	0.54	
Styrene	0.26	100.00
Polystyrene	0.16	
PETROCOQUE S.A.:		
Calcined petroleum coke	0.50	50.00

(1) Feedstock for the production of biodegradable detergents.

Our investments in petrochemical companies amount to U.S.$2,856 million and the most significant investment is in Braskem S.A. (Braskem), Brazil's largest petrochemical company.

We have three new petrochemical projects under construction or in various stages of engineering or design:

- Complexo Petroquímico do Rio de Janeiro—Comperj: designed to meet the Brazilian demand for thermoplastic resins. The petrochemical plants are in the planning stage and are scheduled to start up in 2018;
-

PetroquímicaSuape Complex in Pernambuco: to produce purified terephthalic acid (PTA) with a capacity of 0.7 million t/y (already in operation), polyethylene terephthalate (PET) resin with a capacity of 0.45 million t/y, and polymer and polyester filament textiles with a capacity of 0.24 million t/y; and

- Companhia de Coque Calcinado de Petróleo—Coquepar: calcined petroleum coke plant in the State of Paraná, with a capacity of 0.35 million t/y.

Distribution

Distribution Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Distribution:			
Sales revenues	40,712	44,001	37,282
Income (loss) before income taxes	1,386	1,134	1,081
Total assets at December 31	8,130	7,938	7,384
Capital expenditures and investments	666	679	515

We are Brazil’s leading oil products distributor, operating through our own retail network, through our own wholesale channels, and by supplying other fuel wholesalers and retailers. Our Distribution segment sells oil products that are primarily produced by our Refining, Transportation and Marketing segment, or RTM, and works to expand the domestic market for these oil products and for other fuels, including LPG, ethanol and biodiesel.

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The primary focus of our Distribution segment is to:

- Lead the market in the domestic distribution of oil products and biofuels, increasing our market share and profit through an integrated supply chain; and

- Be the preferred brand of our consumers while upholding and promoting social and environmental responsibility.

We supply and operate Petrobras Distribuidora S.A.—BR, which accounts for 38.1% of the total Brazilian retail and wholesale distribution market. BR distributes oil products, ethanol and biodiesel, and vehicular natural gas to retail, commercial and industrial customers. In 2012, BR sold the equivalent of 885 mbbl/d of oil products and other fuels to wholesale and retail customers, of which the largest portion (43.6%) was diesel.

At December 31, 2012, our BR branded service station network was Brazil’s leading retail marketer, with 7,641 service stations, or 19.5% of the stations in Brazil. BR-owned and franchised stations make up 30.6% of Brazil’s retail sales of diesel, gasoline, ethanol, vehicular natural gas and lubricants.

Most BR stations are owned by franchisees that use the BR brand name under license and purchase exclusively from us; we also provide franchisees with technical support, training and advertising. We own 743 of the BR stations and are required by law to subcontract the operation of these owned stations to third parties. We believe that our market share position is supported by a strong BR brand image and by the remodeling of service stations and addition of lubrication centers and convenience stores.

Our wholesale distribution of oil products and biofuels under the BR brand to commercial and industrial customers accounts for 54.9% of the total Brazilian wholesale market. Our customers include aviation, transportation and industrial companies, as well as utilities and government entities.

Our LPG distribution business, Liquigas Distribuidora, held a 22.6% market share and ranked second in LPG sales in Brazil in 2012, according to the ANP.

Oil products sales in Brazil increased 6.5% in 2012 compared to 2011. This increase was due mainly to Brazil’s economic growth and its corresponding growth in household income and consumer credit.

We participate in the retail sector in other South American countries through our International business segment. See “—International.”

Gas and Power

Gas and Power Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Gas and Power:			
Sales revenues	11,803	9,738	8,492
Income (loss) before income taxes	1,277	2,725	990
Total assets at December 31	28,454	27,645	30,109
Capital expenditures and investments	2,113	2,293	3,964

Our Gas and Power segment comprises gas transmission and distribution, LNG regasification, the manufacture of nitrogen-based fertilizers, gas-fired and flex-fuel power generation, and power generation from renewable sources, including solar, wind and small-scale hydroelectric.

The primary focus of our Gas and Power segment is to:

- Add value by monetizing Petrobras' natural gas resources;
- Assure flexibility and reliability in the commercialization of natural gas;
- Expand the use of LNG to meet Brazilian gas demand and diversify our supply of natural gas;
- Optimize our thermoelectric power plant portfolio and supplement it with power generation from renewables; and
- Create an additional flexible means of monetizing our natural gas resources by investing in capacity to manufacture nitrogen fertilizers.

As a result of our efforts to develop the market, natural gas in the year of 2011 supplied 10.2% of Brazil's total energy needs, compared to 3.7% in 1998, and is projected to supply 15.5% of Brazil's total energy needs by 2021, according to Empresa de Pesquisa Energética, a branch of the MME.

Natural Gas

We have three principal markets for natural gas:

- Industrial, commercial and retail customers;
- Thermoelectric generation; and
- Consumption by our refineries and fertilizer plants.

Natural gas consumption in Brazil by industrial, commercial and retail customers decreased 0.5% in 2012 compared to 2011. This decrease was due mainly to Brazil's low economic growth. Natural gas consumption in the power generation industry increased 105% from 2011 to 2012 due to unfavorable rainfall, which reduced the reservoir storage levels of Brazilian hydroelectric power plants. Natural gas consumption by refineries and fertilizer plants increased 13%.

As a result of a multi-year infrastructure development program, including investments of approximately U.S.$13 billion (R$25.48 billion) in the last five years, we now have an integrated system centered around two main, interlinked pipeline networks that allow us to deliver natural gas from our main offshore natural gas producing fields in the Santos, Campos and Espírito Santo Basins, as well as from three LNG terminals, one of which is under construction, and a gas pipeline connection with Bolivia.

Currently, our natural gas pipeline network has a total extension of 9,190 km. In 2012, we invested U.S.$1,243.2 million in our natural gas infrastructure, and in 2013, we plan to invest an additional U.S.$1,003.7 million for enhancements to our gas transportation system primarily directed to expanding the Cabiúnas Terminal natural gas processing capacity in order to receive up to 459 mmcf/d (13 mmm^3/d) in expectation of increasing associated natural gas production from the pre-salt reservoirs in the Santos Basin. This project is scheduled to be fully operational by August 2014.

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The map below shows our gas pipeline networks and LNG terminals.

We own and operate two LNG flexible terminals using two FSRUs (Floating Storage and Regasification Units), one in Guanabara Bay (Rio de Janeiro) with a send-out capacity of 706 mmcf/d (20 mmm^3/d), and the other in Pecém (Ceará) in Northeastern Brazil with a send-out capacity of 247 mmcf/d (7 mmm^3/d).

We continue to increase our capacity to regassify LNG imports. In 2012 the FSRU which operated at the Guanabara Bay Terminal with send-out capacity of 494 mmcf/d (14 mmm3/d) was replaced by another FSRU with a higher send-out capacity of 706 mmcf/d (20 mmm3/d). Additionally, we are building a third LNG terminal in the State of Bahia, the construction of which began in 2012 and which will be completed in 2013, and will operate with a send-out capacity of 494 mmcf/d (14 mmm^3/d). In 2012, we imported into Brazil 39 LNG cargoes (net).

We hold interests ranging from 24% to 100% in 21 of Brazil's 27 local gas distribution companies. We had approximately a 25% net equity interest in the combined 1,932 mmcf/d (54.7 mmm^3/d) of natural gas distributed by Brazil's local distribution companies in 2012.

According to our estimates, our two most significant holdings, CEG Rio and Bahiagás, are Brazil's third and fourth largest gas distributors. These companies, together with independent distributors Comgás and CEG supply 60% of the Brazilian market.

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Principal Natural Gas Local Distribution Holdings

Name	State	Group Interest %	Average Gas Sales in 2012 (mmm³/d)	Customers
CEG RIO	Rio de Janeiro	37.41	6.6	33,333
BAHIAGAS	Bahia	41.50	3.7	14,335
GASMIG	Minas Gerais	40.00	3.6	406
PETROBRAS DISTRIBUIDORA	Espírito Santo	100.00	3.0	25,828

The table below shows the sources of our natural gas supply, our sales and internal consumption of natural gas, and revenues in our local gas distribution operations for each of the past three years.

Supply and Sales of Natural Gas in Brazil, mmm³/d

	2012	2011	2010
Sources of natural gas supply			
Domestic production	39.5	34.1	28.6
Imported from Bolivia	27.0	27.1	27.1
LNG	8.4	1.6	7.6
Total natural gas supply	**74.9**	**62.8**	**63.3**
Sales of natural gas			
Sales to local gas distribution companies(1)	39.3	39.8	37.2
Sales to gas-fired power plants	16.6	8.2	12.2
Total sales of natural gas	**55.9**	**48.0**	**49.4**
Internal consumption (refineries, fertilizer and gas-fired power plants)(2)	18.5	14.8	13.9
Revenues (U.S.$ billion)(3)	8.1	5.9	4.7

(1) Includes sales to local gas distribution companies in which we have an equity interest.

(2) Includes gas used in the transport system.

(3) Excludes internal consumption.

Long-Term Natural Gas Commitments

When we began construction of the Bolivia-Brazil pipeline in 1996, we entered into a long-term Gas Supply Agreement, or GSA, with the Bolivian state-owned company Yacimientos Petrolíferos Fiscales Bolivianos, or YPFB, to purchase certain minimum volumes of natural gas at prices linked to the international fuel oil price through 2019, after which the agreement may be extended until all contracted volume has been delivered.

On December, 19, 2009, Petrobras and YPFB signed the fourth amendment to the GSA, which provides for annual additional payments to YPFB for liquids contained in the natural gas purchased by Petrobras through the GSA. As of February 2010, Petrobras has paid all obligations owed for 2007, but YPFB did not meet the condition precedent necessary to receive additional payments for the subsequent years (after 2007). Petrobras and YPFB are currently discussing several aspects of the GSA, including payments for liquids contained in the natural gas purchased in the subsequent years (after 2007). As a result of this negotiation, Petrobras may agree to make additional payments in exchange for certain compensations to be agreed by YPFB, but it is currently not possible to provide any specific payment estimates for subsequent years. As a result, we have not considered them in our contractual GSA obligations forecast.

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Our volume obligations under the ship-or-pay arrangements entered into with Gás Transboliviano (GTB) and Transportadora Brasileira Gasoduto Bolivia-Brasil (TBG) were generally designed to match our gas purchase obligations under the GSA through 2019. The tables below show our contractual commitments under these agreements for the five-year period from 2013 through 2017.

Commitments to Purchase and Transport Natural Gas in Connection with Bolivia-Brazil Pipeline

	2013	2014	2015	2016	2017
Purchase commitments to YPFB					
Volume obligation (mmm^3/d)(1)	24.06	24.06	24.06	24.06	24.06
Volume obligation (mmcf/d)(1)	850.00	850.00	850.00	850.00	850.00
Brent crude oil projection (U.S.$)(2)	107.16	104.73	100.00	100.00	100.00
Estimated payments (U.S.$ million)(3)	2,844.30	2,701.10	2,575.70	2,589.40	2,604.00
Ship-or-pay contract with GTB					
Volume commitment (mmm^3/d)	30.08	30.08	30.08	30.08	30.08
Volume commitment (mmcf/d)	1,062.26	1,062.26	1,062.26	1,062.26	1,062.26
Estimated payments (U.S.$ million)(5)	138.46	139.14	139.82	140.51	141.21
Ship-or-pay contract with TBG					
Volume commitment (mmm^3/d)(4)	35.28	35.28	35.28	35.28	35.28
Volume commitment (mmcf/d)	1,246.09	1,246.09	1,246.09	1,246.09	1,246.09
Estimated payments (U.S.$ million)(5)	529.44	508.87	516.38	521.50	524.01

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(1) 25.3% of contracted volume supplied by Petrobras Bolivia.

(2) Brent price forecast based on our 2020 Strategic Plan.

(3) Estimated payments are calculated using gas prices expected for each year based on our Brent price forecast. Gas prices may be adjusted in the future based on

contract clauses and amounts of natural gas purchased by Petrobras may vary annually.

(4) Includes ship-or-pay contracts relating to TBG's capacity increase.

(5) Amounts calculated based on current prices defined in natural gas transport contracts.

Gas Sales Contracts

We sell our gas primarily to local gas distribution companies and to gas fired plants generally based on standard take-or-pay long term supply contracts. This represents 72% of our total sale volumes and the price formula under these contracts are indexed to an international fuel oil basket.

Additionally, we have a variety of supply contracts designed to create flexibility in matching customer demand with our gas supply capabilities. These include flexible and interruptible long-term gas supply contracts, auction mechanisms for short-term contracts, weekly electronic auctions and a new gas sale contract introduced in 2011, which consists of a seller delivery option aiming to help balance natural gas supply and demand in case of a low dispatch of natural gas from gas-fired power plants.

In 2012, we renegotiated some existing long-term natural gas sales contracts with local distribution company of natural gas in order to promote adjustments tailored to specific market demands, encompassing term extensions for some contracts, prolonging our natural gas procurement portfolio. We continued offering contracts for short-term volumes through electronic auctions.

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The table below shows our future gas supply commitments from 2013 to 2017, including sales to both local gas distribution companies and gas-fired power plants.

Future Commitments under Natural Gas Sales Contracts, mmm³/d

	2013	**2014**	**2015**	**2016**	**2017**
To local gas distribution companies:					
Related parties(1)	19.16	21.07	20.51	21.24	21.65
Third parties	16.84	16.90	16.93	16.93	16.93
To gas-fired power plants:					
Related parties(1)	6.79	4.66	2.52	2.54	2.59
Third parties	6.55	7.93	8.27	8.32	8.60
Total(2)	**49.34**	**50.56**	**48.23**	**49.03**	**49.77**
Estimated contract revenues (U.S.$ billion)(3)(4)	6.4	6.9	7.0	7.1	7.4

(1) For purposes of this table, "related parties" include all local gas distribution companies and power generation plants in which we have an equity interest and "third parties" refer to those in which we do not have an equity interest.

(2) Estimated volumes are based on "take or pay" agreements in our contracts, expected volumes and contracts under negotiation (including renewals of existing contracts), not maximum sales.

(3) Figures show revenues net of taxes. Estimates are based on outside sales and do not include internal consumption or transfers.

(4) Prices may be adjusted in the future and actual amounts may vary.

Short-Term Natural Gas Sales

In 2009, we contributed to the development of a short-term market for natural gas sales, focusing on the industrial market. Sales under these short-term contracts were accomplished by an electronic auction system. These auctions commercialized natural gas volumes reserved for but not otherwise utilized by local gas distributors, and allowed us to offer to end users more competitive prices.

Since October 2012 we have revised the auction so that one short-term contract will regulate all operations of sales during an one-year period. On average, 4.4 mmm³/d of natural gas were sold under short-term contracts in 2009, with volumes reaching 7.8 mmm³/d in 2010 and 6.7 mmm³/d in 2011. In 2012, the average volumes of natural gas delivered under this new agreement was 6.6 mmm³/d, with a delivery record of 7.3 mmm³/d in October 2012.

Fertilizers

We are expanding production of nitrogenous fertilizers in order to meet the growing needs of Brazilian agriculture, to substitute for imports, and to expand the market for the growing production of our associated natural gas.

Our fertilizer plants in Bahia and Sergipe produce ammonia and urea for the Brazilian market.

The table below shows our ammonia and urea sales, and revenues for each of the past three years:

	Ammonia and Urea (ton)		
	2012	**2011**	**2010**
Ammonia	229,575	240,665	235,729
Urea	848,000	831,462	772,059
Revenues (U.S.$ million)	571	605	421

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We are currently building four additional facilities:

• Sergipe, with the ability to sell 303,000 t/y of ammonium sulfate from 226 t/d of ammonia, expected to start up in May 2013;

• UFN III, with the ability to sell 1.2 million t/y of urea and 70 thousand t/y of ammonia from 2.2 mmm3/d of natural gas, expected to start up in September 2014;

• UFN V, with the ability to sell 519,000 t/y of ammonia from 1.3 mmm^3/d of natural gas, expected to start up in November 2016; and

• UFN IV, with the ability to sell 755,000 t/y of urea and 721,000 t/y of methanol from 3.5 mmm3/d of natural gas, expected to start up in July 2018. 42,000 t/y of melamine will be produced from the foregoing quantity of urea, and 211,000 t/y of acetic acid and 26,000 t/y of formic acid will be produced from the foregoing quantity of methanol.

Power

Brazilian electricity needs are mainly supplied by hydroelectric power plants (84,463 MW of installed capacity) which corresponds to 69% of Brazil's generation capacity. Hydroelectric power plants are dependent on the annual level of rainfall, i.e., in the years where rainfall is abundant, the Brazilian hydroelectric power plants will generate more electricity and consequently less generation from thermoelectric power plants will be demanded. In 2012, hydroelectric power plants in Brazil generated 50,225 MWavg, which corresponded to 86% of Brazil's total electricity needs (58,401 MWavg).

The total installed capacity of the Brazilian National Interconnected Power Grid (*Sistema Interligado Nacional*—SIN) in 2012 was of 122,561 MW. Of this total, 6,235 MW (or 5%) was available from 19 thermoelectric plants which we control. These plants are designed to supplement power from the hydroelectric power plants. In 2012, we invested U.S.$387.8 million (R$760.0 million) in our power business segment.

Hydroelectric generation capacity is supplement by other sources of energy (biomass, wind, coal, nuclear and natural gas). Total electricity generated by these sources averaged 8,176 MW in 2012, of which Petrobras' thermoelectric power plants contributed 2,699 MWavg, as compared to 653 MWavg in 2011. Most of our generation occurred in the fourth quarter when we averaged 5,279 MWavg of generation due to reduced rainfall affecting hydroelectric generation in this period.

Electricity Sales and Commitments for Future Generation Capacity

Under Brazil's power pricing regime, a power plant may sell only electricity that is certified by the MME and which corresponds to a fraction of its installed capacity. This certificate is granted to ensure a constant sale of commercial capacity over the course of years to each power plant, given its role within Brazil's system to supplement hydroelectricity power during periods of unfavorable rainfall. The amount of certified capacity for each power plant is determined by its expected capacity to generate energy over time.

The totality of the capacity certified by the MME (*garantia física)* may be sold through long term contracts in auctions to power distribution companies (standby availability), long term bilateral contracts executed with free customers and to attend the energy needs of our own facilities.

In exchange for selling this certified capacity, the thermoelectric power plants shall produce energy whenever requested by the national operator (ONS). In addition to a capacity payment, thermoelectric power plants also receive from the Electric Energy Trading Chamber (*Câmara de Comercialização de Energia Elétrica*, or "CCEE") reimbursement for its variable costs (previously declared to MME to calculate its commercial certified capacity) incurred whenever they are called to generate electricity.

For the year of 2012, the commercial capacity certified by MME for all thermoelectric power plants controlled by us was of 4,146 MWavg, although our total generating capacity was 6,235 MWavg in 2012. Of the total 4,438 MWavg of commercial capacity available (*capacidade comercial disponível* or *lastro*) for sale in 2012, approximately 38% was sold as standby availability in auctions and approximately 62% was committed under bilateral contracts and self-production.

Under the terms of standby availability contracts, we are compensated a fixed amount whether or not we generate any power. Additionally, whenever we have to deliver energy under such standby availability contracts, we receive an additional compensation for the energy delivered that is set on the date of the auction and is annually revised based on an inflation-adjusted fuel oil basket.

In addition, in the new energy auction (*Leilão de Energia Nova*) held on August 17, 2011, we committed to sell 416.4 MWavg from our Baixada Fluminense plant for the period of March 2014 through December 2033. In 2012, we acquired the Camaçari Polo de Apoio I (Arembepe) and Camaçari Muricy I (Muricy) oil-fired thermoelectric power plants. In the new energy auction held on June 26, 2006, each of them committed to sell 101 MWavg for the period of January 2009 through December 2023.

Our future commitments under bilateral contracts and self-production are of 2,753 MWavg in 2013, 2,420 MWavg in 2014 and 2,407 MWavg in 2015. The agreements will run off gradually, with the last contract expiring in 2028. As existing bilateral contracts run-off, we will sell our remaining certified commercial capacity under short and medium-term bilateral contracts, in new auctions to be conducted by MME or in the spot market.

The table below shows the evolution of our thermoelectric power plants installed capacity and the associated certificated commercial capacity.

Installed Power Capacity, Certified Commercial Capacity

	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Installed power capacity and utilization						
Installed capacity (MW)	5,277	5,806	6,235	6,323	6,379	6,379
Certified commercial capacity (MWavg)	3,619	3,777	4,146	4,342	4,266	4,421
Purchases (MWavg)	234	214	292	209	203	200
Commercial capacity available (*Lastro*) (MWavg)	3,853	3,991	4,438	4,551	4,469	4,621

The table below shows the allocation of our sales volume between our customers and our revenues for each of the past three years:

Volumes of Electricity Sold (MWavg)

	2012	2011	2010
Total sale commitments	**4,438**	**3,991**	**3,853**
Bilateral contracts	2,318	2,000	2,024
Self-production	423	395	438
Auctions to distribution companies	1,697	1,596	1,391
Generation volume	**2,699**	**653**	**1,837**
Revenues (U.S.$ million)	**3,755**	**2,366**	**2,752**

Renewable Energy

We have invested, alone and in partnership with other companies, in renewable power generation sources in Brazil including wind and small hydroelectric plants. Our net interests are equivalent to 316.5 MW of hydroelectric capacity and 105.8 MW of wind capacity. We and our partners sell energy from these plants directly to the Brazilian federal government via the renewable energies incentive program (PROINFA) and the 2009 “reserve energy” auctions.

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International

International Key Statistics

	2012	2011	2010
		(U.S.$ million)	
International:			
Sales revenues	17,929	16,956	13,519
Income (loss) before income taxes	1,933	2,117	1,053
Total assets at December 31	18,735	19,427	16,958
Capital expenditures and investments	2,572	2,631	2,712

We have operations in 21 countries outside of Brazil, encompassing all phases of the energy business. The primary focus of our international operations is to:

- Use our technical and geoscientific knowledge, acquired while operating in offshore Brazil, in areas that exhibit similar characteristics and with large reserves potential, such as West Africa and the Gulf of Mexico; and

- Focus on the gas and power business to complement the natural gas supply to the Brazilian market.

International Upstream Activities

Most of our international activities are in exploration and production of oil and gas. We have long been active in Latin America. In the Gulf of Mexico and West Africa, we focus on opportunities to leverage the deepwater expertise we have developed in Brazil. We have preliminary exploratory efforts underway in other regions.

In 2012, our net production outside Brazil averaged 143.6 mbbl/d of crude oil and NGLs and 651.1 mmcf/d (18.4 mmm^3/d) of natural gas, representing 10% of our total production on a barrels of oil equivalent basis.

The table below shows our main exploration and production projects being developed worldwide, as of December 31, 2012. Additional information about certain of these projects and our exploration and production activities is provided in the text that follows.

Main International Exploration and Production Assets in Development

	Countries	Main projects in development	Phase	Operated by	Petrobras interest (%)
South America					
1	Argentina(1)	Sierra Chata	Production	Petrobras	46
		El Tordillo	Production	Partner	36
		Santa Cruz I Oeste	Production	Petrobras	50

		25 de Mayo – Medanito	Production	Petrobras	100
			Production	Petrobras	
		Rio Neuquen			100
			Production	Petrobras	71
		Santa Cruz I			100
			Production	Petrobras	77
		El Mangrullo			
			Production	Petrobras	
		Entre Lomas			
2	Bolivia	San Alberto	Production	Petrobras	35(2)
		San Antonio	Production	Petrobras	35(2)
					30(2)
		Itaú	Production	Petrobras	
3	Colombia	Guando	Production	Petrobras	15
		Yalea	Production	Partner	50
		Espinal	Production	Petrobras	33
		Balay 1	Development	Petrobras	45
		Tayrona	Exploration	Petrobras	40
		Cebucan	Exploration	Petrobras	50
4	Peru	Lote 10	Production	Petrobras	100
		Lote 57	Development	Partner	46.16
		Lote 58	Exploration	Petrobras	100

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5	Uruguay	Block 3	Exploration	Partner	40
		Block 4	Exploration		
				Petrobras	40
6	Venezuela	Oritupano-Leona	Production	Partner	22(3)
		Acema	Production	Partner	34(3)
		La Concepción	Production	Partner	36(3)
		Mata	Production	Partner	34(3)
North America					
7	Mexico	Cuervito	Production	Petrobras	45(4)
		Fronterizo	Production	Petrobras	45(4)
8	U.S.	Cascade	Production	Petrobras	100
		Chinook	Production	Petrobras	66.67
		Coulumb (MC-613)	Production	Partner	33.33
		Cottonwood	Production	Petrobras	100
		St. Malo	Development	Partner	25
		Tiber	Exploration	Partner	20
		Stones	Development	Partner	25
		Gila	Exploration	Partner	20
		Logan		Partner	35
			Exploration		
		Lucius	Exploration	Partner	9.6
Africa					
9	Angola	Block 2/85	Production	Partner	27.5
		Block 6/06	Exploration	Petrobras	40
		Block 18/06	Exploration	Petrobras	30
		Block 26	Exploration	Petrobras	40
10	Benin	Block 4	Exploration	Partner	35
11	Gabon	Ntsina Marin	Exploration	Partner	50
		Mbeli Marin	Exploration	Partner	50
12	Namibia	2714A	Exploration	Petrobras	30
13	Nigeria	Akpo	Production	Partner	20
		Agbami	Production	Partner	12.5
		Egina	Development	Partner	20
		Egina South	Exploration	Partner	20
		Preowei	Exploration	Partner	20
14	Tanzania	Block 5	Exploration	Petrobras	50
		Block 6	Exploration	Petrobras	50
		Block 8	Exploration	Petrobras	50
Europe					
15	Portugal	Peniche	Exploration	Petrobras	50
		Alentejo	Exploration	Petrobras	50

(1) All Argentine exploration and production projects are held through our indirect 67.2% share in Petrobras Argentina S.A. (PESA).

(2) Production-sharing contract, under which Petrobras' expenditures are reimbursed only if exploration results in economically viable oil discoveries.

(3) Joint venture through Petrobras Argentina S.A. (PESA).

(4) Non-risk service contract, under which Petrobras' expenditures are reimbursed regardless of whether exploration results in economically viable oil discoveries.

During 2012, our capital expenditures and investments for international exploration and production totaled U.S.$2.34 billion, representing 10% of our total exploration and production capital spending.

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South America

We are present in Argentina, Bolivia, Colombia, Peru, Venezuela and Uruguay. In 2012, our average net production from South America (outside of Brazil) was 188.2 mboe/d, or 75% of our international production. Reserves in the region represent 62% of our international reserves. Our most significant natural gas production operations outside of Brazil are located in Argentina and Bolivia, where we produced an average 618.3 mmcf/d (17.5 mmm^3/d) of natural gas in 2012, or 95% of our international production.

Our largest operating region outside Brazil is **Argentina**, where we operate primarily through our 67.2% interest in Petrobras Argentina S.A., or PESA. Our main oil production is concentrated in the Medanito, Entre Lomas, El Tordillo, La Tapera – Puesto Quiroga and Puesto Hernández fields, and our main gas production is concentrated in the El Mangrullo, Río Neuquém fields in the Neuquém basin and Santa Cruz I fields in the Austral basin. As of May 2012, after a corporate reorganization, PESA has a 58.9% interest in Petrolera Entre Lomas S.A. (PELSA), whose main oil production is concentrated in the Entre Lomas field. In the second half of 2012, Petrobras announced reserves discoveries in the Estancia Agua Fresca and in the Estancia Campos fields, both in the province of Santa Cruz, with estimated reserves of 6 million boe and 11 million boe, respectively.

In **Bolivia**, our production comes principally from the San Alberto, San Antonio and Itaú fields. Following enactment of the Bolivian government's May 1, 2006 nationalization of hydrocarbons, we entered into new production-sharing contracts under which we continue to operate the fields, but are required to make all hydrocarbon sales to YPFB with the right to recover our costs and participate in profits. On January 25, 2009, Bolivia adopted a new constitution that prohibits private ownership of the country's oil and gas resources. As a result, we were not able to include any of our Bolivian proved reserves in our consolidated proved reserves since year-end 2009. We continue to report production from our operations in Bolivia under our existing contracts in that country.

In **Colombia**, our production during 2012 was originated mainly from the Guando and Espinal blocks. Our portfolio in Colombia also includes the Canada Norte and Balay blocks, currently in its development stage, and the Cebucan and Tayrona blocks, among others, which are currently in the exploratory stage. In the second half of 2012, we confirmed the presence of approximately 23.9° API oil in the Guando SW1 well located in the Boqueron block. In October 2012, we began the long duration test. We will resume tests to evaluate the potential of discovery.

In **Venezuela**, we are present through four joint ventures with subsidiaries of Petróleos de Venezuela S.A., or PDVSA, which hold production rights and in which we hold minority interests. PDVSA is the majority holder and operator.

In **Peru**, our production during 2012 was originated from Lote 10. Our portfolio in Peru also includes Lote 57 and Lote 58. Lote 57 comprises the Kinteroni Gas Project, currently in its development stage, and another component of Lote 57 currently in the exploratory stage. The Lote 58 is in exploratory stage, but we made three successive discoveries with gas potential, in 2009 at the Urubamba prospect, in 2010 at Picha prospect and in 2011 at the Taini prospect. Currently we are waiting the completion of the Paratori-4X well to evaluate its potential.

In **Uruguay**, we have interest in two explorations offshore blocks since 2009 through a consortium between us, YPFB and Galp Energia. These offshore blocks are located in the Punta del Este Basin in water depths ranging from 15 to 3,500 meters.

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North America

In the **United States**, we focus on deepwater fields in the Gulf of Mexico. As of December 31, 2012, we held interests in 170 offshore blocks, 118 of which we operate. Our production in the United States during 2012 was originated mainly from the Cascade and Coulumb fields. The Cascade and Chinook fields began oil production in February 2012 and September 2012, respectively. These projects are the first Gulf of Mexico operation to use a FPSO. Other assets include the Saint Malo, Stones and Lucius blocks, which are currently in the development stage, and Gila, Tiber and Logan, among others, which are currently in the exploratory stage.

We have held non-risk service contracts through our joint venture with PDT Servicios Multiples SRL for the Cuervito and Fronterizo Blocks in the Burgos Basin of **Mexico** since 2003. Under these service contracts, we receive fees for our services, but any producing wells and production are transferred to the Mexican national oil company Petróleos Mexicanos, or Pemex.

Europe

Under two concession agreements we are analyzing seismic data related to the Peniche and Alentejo Basins offshore **Portugal**.

Africa

In **Angola**, our production in 2012 was originated from Block 2, which we do not operate. Petrobras operates blocks 6/06, 18/06 and 26, all in exploratory phase.

In **Benin**, we completed a 3D seismic study and will drill the first well in Block 4 in 2013, which covers an area of approximately 7,400 km² and has water depths ranging from 200 to 3,200 meters (656 to 10,498 feet).

In **Gabon**, we are performing a 3D seismic study in the Ntsina Marin and Mbeli Marin blocks, with water depths up to 2,200 meters (7,217 feet).

In **Namibia**, we drilled the first well but have made no discovery. We are currently evaluating the remaining potential of Block 2714A. This block is located in offshore Southern Namibia and covers an area of approximately 5,500 km2 (1.4 million acres) in water depths from 150 to 1,500 meters (492 to 4,921 feet).

In **Nigeria**, our production was originated from the Agbami and Akpo fields, and we also have an interest in the Egina field project, currently in its development stage while the Preowei and Egina South fields are under appraisal.

In **Tanzania**, we operate three offshore exploration blocks, Blocks 5, 6 and 8, and are performing 3D seismic studies.

Oceania

In **New Zealand**, we halted activities as the 2D seismic survey did not identify economic potential reserves of oil and gas in the Raukumara Basin.

Other International Activities

Our other international activities, including refining, petrochemicals, distribution and gas and power activities, are described below.

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South America

We have integrated operations in **Argentina**, where we participate across the energy value chain. We own, through our interest in PESA, the Bahia Blanca Refinery, with a capacity of 30.5 mbbl/d. We also hold an interest in the Refinor/Campo Duran Refinery and in two petrochemical plants in Argentina. We own 271 retail service stations. We also own two electricity power plants, Pichi Picún Leufú (hydrogeneration) and Genelba (combined cycle), as well as interest in a natural gas transportation company called TGS (Transportadora Gas del Sur), and in Mega Company, a natural gas separation facility.

In January 2013, PESA sold to Hidroeléctrica Piedra del Águila S.A. and La Plata Cogeneración S.A. all the shares of Petrobras Electricidad de Argentina S.A., or PEDASA and Petrobras Finance Bermuda Ltd., or PFB, for an amount of U.S.$35 million. PEDASA and PFB hold a 38.5% and 10% interest, respectively, in Distrilec, which holds a 56.36% interest in Empresa Distribuidora Sur S.A. (Edesur), an energy marketer company.

In **Bolivia**, we operate gas fields that supply gas to Brazil and Bolivia. We hold an 11% interest in GTB, owner of the Bolivian section of the Bolivia-to-Brazil (BTB) pipeline that transports natural gas we produce in Bolivia to the Brazilian market. We also hold a 44.5% interest in Transierra S.A., which owns the Yacuiba-Rio Grande gas pipeline (Gasyrg) linking the San Alberto, San Antonio and Itaú fields to the BTB pipeline.

In **Chile**, our assets comprise 243 service stations, the distribution and sales of fuel at 11 airports and a lubricant plant.

In **Colombia**, our assets comprise 91 service stations and a lubricant plant.

In **Paraguay**, our assets comprise 173 service stations, the distribution and sales of fuel at two airports and one LPG refueling plant.

In **Uruguay**, we have fuel distribution operations, with 88 service stations. We also market marine products, asphalt and aviation products and distribution.

The portfolio of our Gas segment includes two gas distribution companies in Uruguay, namely, Distribuidora de Gas Montevideo S.A (with retail sales in Montevideo) and Conecta S.A. (with national commercial sales). See "—Gas and Power".

North America

In the **United States**, we own 100% of the Pasadena Refining System, or PRSI, and 100% of PRSI's related trading company - PRSI Trading Company. On June 29, 2012, we executed an agreement to settle all existing disputes with the Transcor/Astra group, which controls Astra Oil Trading NV (Astra). The lawsuits stemmed from the partnership period between Astra and

Petrobras America, Inc., or PAI, our indirect subsidiary in the United States, in PRSI and PRSI Trading Company. The agreement also ended the litigation relating to the arbitration award that had recognized Astra's put option of its ownership interest in PRSI and PRSI Trading Company, which forced PAI to purchase said ownership interest. In the settlement, PAI paid the put option value set by an arbitral award dated April 10, 2009, plus interest and other legal expenses, totaling U.S.$820.5 million. This amount was already provisioned for payment, almost in full, in our audited consolidated financial statements at year-end 2009, 2010 and 2011. The remaining amount of approximately U.S.$70 million was included in our results of operations for the second quarter of 2012.

Asia

In **Japan**, we own the Nansei Sekiyu Kabushiki Kaisha (NSS) refinery in Okinawa, which currently produces refined products such as gasoline, diesel, fuel oil and jet fuel.

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Biofuels

Biofuels Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Biofuel:			
Sales revenues	455	320	272
Income (loss) before income taxes	(156)	(151)	(77)
Total assets at December 31	1,248	1,289	1,133
Capital expenditures	147	294	664

Brazil is a global leader in the use and production of biofuels. Today, 83.1% of new light vehicles sold in Brazil have flexfuel capability, and service stations offer a choice of 100% ethanol and an ethanol/gasoline blend.

Biodiesel

Since January 2010, all diesel fuel sold in Brazil is required to have at least 5% biodiesel. We supply 20.2% of Brazil's biodiesel and we act as a market catalyst by securing and blending biodiesel supplies and furnishing these to smaller distributors as well as our own service stations. We directly own three biodiesel plants and through our 50% interest in BSBIOS Energia Renovável S.A. (BSBIOS) we own two additional plants. The biodiesel production capacity of these five plants totals 13.1 mbbl/d, ranking us amongst the five main biodiesel producers in Brazil.

Ethanol

Due to our ownership interest in Guarani S.A. (Guarani), Brazil's third largest sugarcane processor, Nova Fronteira Bioenergia S.A. (Nova Fronteira) and Total Agroindústria Canavieira S.A. (Total Agroindústria), we also have presence in the whole ethanol production chain in the production and distribution of ethanol and selling the exceeding electricity generated from sugarcane bagasse burn. We have all necessary infrastructure for the distribution and export of ethanol.

In 2012, we invested approximately U.S.$104.0 million (R$212.5 million) in Guarani, increasing our interest to 35.76% from 31.44%.

Through our affiliated companies Total Agroindústria, Nova Fronteira and Guarani, we also own ethanol plants situated in the States of Minas Gerais, São Paulo and Goiás and also an ethanol plant in Mozambique, Africa. These affiliated companies' total milling capacity in the 2012/2013 harvest amounted to 22.5 mmt of sugarcane, and the total ethanol and sugar production capacity of our affiliate companies amounted to 14.2 mbbl/d and 1.6 mmt respectively. These affiliated entities sold 535GWh of exceeding electricity generated during the 2012/2013 harvest.

In 2012, we exported 545 mbbl/y of ethanol, 2.84% of Brazil's total ethanol exports, which consisted mainly of industrial and hydrous ethanol exported to Asia. In addition, we also increased the volume of ethanol bought outside of Brazil, which reached a volume of 416 mbbl/y.

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Corporate

Corporate Key Statistics

	2012	2011	2010
		(U.S.$ million)	
Corporate:			
Income (loss) before income taxes	(6,999)	(5,003)	(3,572)
Total assets at December 31	39,125	45,777	53,631
Capital expenditures and investments	747	729	839

Our Corporate segment comprises activities that cannot be attributed to other segments, including corporate financial management, central administrative overhead and actuarial expenses related to our pension and medical benefits for retired employees and their dependents. As of 2011, the results of our Biofuel segment have been presented separately from our Corporate segment. The 2010 financial information related to our Corporate and Biofuel segments was reclassified accordingly.

Organizational Structure

We have 39 direct subsidiaries as listed below. 32 are incorporated under the laws of Brazil and seven are incorporated abroad (including PifCo). We also have indirect subsidiaries, including PGF. See Exhibit 8.1 for a complete list of our subsidiaries, including their full names, jurisdictions of incorporation and our percentage equity interest.

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Property, Plant and Equipment

Our most important tangible assets are wells, platforms, refining facilities, pipelines, vessels and other transportation assets, and power plants. Most of these are located in Brazil. We own and lease our facilities and some owned facilities are subject to liens, although the value of encumbered assets is not material.

We have the right to exploit crude oil and gas reserves in Brazil under concession agreements, but the reserves themselves are the property of the government under Brazilian law. Item 4. "Information on the Company" includes a description of our reserves and sources of crude oil and natural gas, key tangible assets, and material plans to expand and improve our facilities.

Regulation of the Oil and Gas Industry in Brazil

Concession Regime for Oil and Gas

Under Brazilian law, the Brazilian federal government owns all crude oil and natural gas subsoil accumulations in Brazil. The Brazilian federal government holds a monopoly over the exploration, production, refining and transportation of crude oil and oil products in Brazil and its continental shelf, with the exception that companies that were engaged in refining and distribution in 1953 were permitted to continue those activities. Between 1953 and 1997, we were the Brazilian federal government's exclusive agent for exploiting its monopoly, including the importation and exportation of crude oil and oil products.

As part of a comprehensive reform of the oil and gas regulatory system, the Brazilian Congress amended the Brazilian Constitution in 1995 to authorize the Brazilian federal government to contract with any state or privately-owned company to carry out upstream, oil refining, cross-border commercialization and transportation activities in Brazil of oil, natural gas and their respective products. On August 6, 1997, Brazil enacted Law No. 9,478, which established a concession-based regulatory framework, ended our exclusive right to carry out oil and gas activities, and allowed competition in all aspects of the oil and gas industry in Brazil. Since that time, we have been operating in an increasingly deregulated and competitive environment. Law No. 9,478 also created an independent regulatory agency, the ANP, to regulate the oil, natural gas and renewable fuel industry in Brazil, and to create a competitive environment in the oil and gas sector. Effective January 2, 2002, Brazil deregulated prices for crude oil, oil products and natural gas.

Law No. 9,478 established a concession-based regulatory framework and granted us the exclusive right to exploit crude oil reserves in each of our producing fields under the existing concession contracts for an initial term of 27 years from the date when they were declared commercially profitable. These are known as the "Round Zero" concession contracts. This initial 27-year period for production can be extended at the request of the concessionaire and subject to approval from the ANP. Law No. 9,478 also established a procedural framework for us to claim exclusive exploratory rights for a period of up to three years, later extended to five years, to areas where we could demonstrate that we had made commercial discoveries or exploration investments prior to the enactment of the Law No. 9,478. In order to perfect our claim to explore and develop these areas, we had to demonstrate that we had the financial capacity to carry out these activities, either alone or through other cooperative arrangements. Starting in 1999, all areas not already subject to concessions became available for public bidding conducted by the ANP. All the concessions that we have obtained since such time were obtained through participation in public bidding rounds.

Taxation under Concession Regime for Oil and Gas

According to the Law No. 9,478 and under our concession agreements for exploration and production activities with ANP, we are required to pay the government the following:

- Signature bonuses paid upon the execution of the concession agreement, which are based on the amount of the winning bid, subject to the minimum signature bonuses published in the relevant bidding guidelines (*edital de licitação*);

- Annual retention bonuses for the occupation or retention of areas available for exploration and production, at a rate established by the ANP in the relevant bidding guidelines based on the size, location and geological characteristics of the concession block;

- Special participation charges at a rate ranging from 0 to 40% of the net income derived from the production of fields that reach high production volumes or profitability, according to the criteria established in the applicable legislation. Net revenues are gross revenues less royalties paid, investments in exploration, operational costs and depreciation adjustments and applicable taxes. The Special Participation Tax uses as a reference international oil prices converted to *reais* at the current exchange rate. In 2012, we paid this tax on 19 of our fields, namely Albacora, Albacora Leste, Barracuda, Cachalote, Canto do Amaro, Caratinga, Carmópolis, Espadarte, Jubarte, Leste do Urucu, Lula, Manati, Marlim, Marlim Leste, Marlim Sul, Pampo, Rio Urucu, Roncador and Frade (operated by Chevron); and

- Royalties, to be established in the concession contracts at a rate ranging between 5% and 10% of gross revenues from production, based on reference prices for crude oil or natural gas established by Decree No. 2,705 and ANP regulatory acts. In establishing royalty rates in the concession contracts, the ANP also takes into account the geological risks and expected productivity levels for each concession. Virtually all of our crude oil production is currently taxed at the maximum royalty rate.

Law No. 9,478 also requires concessionaires of onshore fields to pay to the owner of the land a participation fee that varies between 0.5% and 1.0% of the sales revenues derived from the production of the field.

Production-Sharing Contract Regime for Unlicensed Pre-Salt and Potentially Strategic Areas

Discoveries of large petroleum and natural gas reserves in the pre-salt areas of the Campos and Santos Basins prompted a change in the legislation regarding oil and gas exploration and production activities.

In 2010, three new laws were enacted to regulate exploration and production activities in pre-salt and other potentially strategic areas not subject to existing concessions: Law No. 12,351, Law No. 12,304, and Law No. 12,276. The enacted legislation does not impact the existing pre-salt concession contracts, which cover approximately 28% of the pre-salt areas.

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Law No. 12,351, enacted on December 22, 2010, regulates production-sharing contracts for oil and gas exploration and production in pre-salt areas not under concession and in potentially strategic areas to be defined by the CNPE. Under the production-sharing regime, we will be the exclusive operator of all blocks. The exploration and production rights for these blocks can either be granted to us on an exclusive basis or, in the case where they are not awarded to us on an exclusive basis, they will be offered under public bids. If offered under public bids, we would still be required to participate as the operator, with a minimum interest to be established by the CNPE that would not be less than 30%, with the additional right, at our discretion, to participate in the bidding process to increase our interest in those areas. Under the production-sharing regime, the winner of the bid will be the company that offers to the Brazilian federal government the highest percentage of “profit oil,” which is the production of a certain field after deduction of royalties and “cost oil,” which is the cost associated with oil production. According to Law No. 12,351, we must accept the economic terms of the winning bid.

Law No. 12,734 became partially effective on November 30, 2012 and amended Law 12,351 establishing a royalty rate of 15% applicable to the gross production of oil and natural gas under future production sharing contracts. On March 14, 2013, an additional provision of Law 12,734/2012 became effective to change the existing rules about distribution of revenues from royalties imposed on oil and gas companies among the Brazilian federal government, states and municipalities. Under the new law, the percentage of the total royalties distributed to oil-producing states and municipalities was reduced and non-producing states and municipalities will from now on receive more revenues from royalties derived from oil and gas activities in Brazil. The royalties revenues redistribution under this law affects not only future concession agreements but also concession agreements that are currently in force. The validity of this law is currently being challenged before the Brazilian Supreme Court by oil-producing states and although it is uncertain whether the Supreme Court will uphold its validity on March 18, 2013, the Brazilian Supreme Court issued an injunction suspending the effects of the aforementioned law. It is also unclear if and how oil-producing states and municipalities would be compensated for their loss of revenues from oil and gas royalties. Although the new law does not increase the total amount of royalties payable by us, oil-producing states and municipalities may raise other applicable tax rates or create additional taxes to the oil and gas industry as a whole in order to compensate the revenue loss they will have as a result of the new law.

Law No. 12,304, enacted on August 2, 2010, authorizes the incorporation of a new state-run non-operating company that will represent the interests of the Brazilian federal government in the production-sharing contracts and will manage the commercialization contracts related to the Brazilian federal government’s share of the “profit oil.” This new company will participate in operational committees, with a casting vote and veto powers, as defined in the contract, and will manage and control costs arising from production-sharing contracts. Where production-sharing contracts are concerned, this new company will exercise its specific legal activities alongside the ANP, the independent regulatory agency that regulates and oversees oil and gas activities under all exploration and production regimes, and the CNPE, the entity that sets the guidelines to be applied to the oil and gas sector, including with respect to the new regulatory model.

Assignment Agreement (Cessão Onerosa) and Global Offering

Pursuant to Law No. 12,276, enacted on June 30, 2010, we entered into an agreement with the Brazilian federal government on September 3, 2010 (Assignment Agreement), under which the government assigned to us the right to conduct activities for the exploration and production of oil, natural gas and other fluid hydrocarbons in specified pre-salt areas, subject to a maximum production of five billion barrels of oil equivalent. The initial contract price for our rights under the Assignment Agreement was R$74,807,616,407, which was equivalent to U.S.$42,533,327,500 as of September 1, 2010. See Item 10. "Material Contracts—Assignment Agreement."

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Natural Gas Law of 2009

In March 2009, the Brazilian Congress enacted Law No.11,909, or Gas Law, regulating activities in the gas industry, including transport, processing, storage, liquefaction, regasification and commercialization. The Gas Law created a concession regime for the construction and operation of new pipelines to transport natural gas, while maintaining an authorization regime for pipelines subject to international agreements. According to the Gas Law, after a certain exclusivity period, operators will be required to grant access to transport pipelines and maritime terminals, except LNG terminals, to third parties in order to maximize utilization of capacity. Authorizations previously issued by the ANP for natural gas transport will remain valid for 30 years from the date of publication of the Gas Law, and initial carriers were granted exclusivity in these pipelines for 10 years. The ANP will issue regulations governing third-party access and carrier compensation if no agreement is reached between the parties.

The Gas Law also authorized certain consumers, which can purchase natural gas on the open market or obtain their own supplies of natural gas, to construct facilities and pipelines for their own use in the event local gas distributors controlled by the states, which have monopoly over local gas distribution, do not meet their distribution needs. These consumers are required to delegate the operation and maintenance of the facilities and pipelines to local gas distributors, but they are not required to sign gas supply agreements with the local gas distributors.

In December 2010, Decree No. 7,382 was enacted in order to regulate Chapter I to VI and VIII of the Gas Law as it relates to activities in the gas industry, including transportation and commercialization. Since the publication of this decree, various administrative regulations were enacted by the ANP and the MME in order to regulate various issues in the Gas Law and Decree No. 7,382 that needed to be further clarified.

Price Regulation

Until the passage of Law No. 9,478 in 1997, the Brazilian federal government had the power to regulate all aspects of the pricing of crude oil, oil products, ethanol, natural gas, electric power and other energy sources. In 2002, the government eliminated price controls for crude oil and oil products, although it retained regulation over certain natural gas sales contracts and electricity. Also in 2002, the Brazilian federal government established an excise tax on the sale and import of crude oil, oil products and natural gas products (*Contribuição de Intervenção no Domínio Econômico*, Contribution for Intervention in the Economic Sector, or CIDE) which is currently at 0% tax rate for gasoline, diesel, ethanol and other products. The Brazilian federal government has periodically used CIDE as a tool to maintain price stability to end consumers, primarily by decreasing the CIDE rate when we increase our prices to reflect higher international prices and vice versa. In 2009, the Gas Law authorized the ANP to regulate prices for the use of gas transport pipelines subject to the new concession regime, based on a procedure defined in the Gas Law as a "*chamada pública*," and to approve prices submitted by carriers, according to previously established criteria, for the use of new gas transport pipelines subject to the authorization regime.

Environmental Regulations

All phases of the crude oil and natural gas business present environmental risks and hazards. Our facilities in Brazil are subject to a wide range of federal, state and local laws, regulations and permit requirements relating to the protection of human health and the environment. At the federal level, our offshore activities and those that involve more than one Brazilian state are subject to the regulatory authority of the *Conselho Nacional do Meio Ambiente* (National Council for the Environment, or CONAMA) and to the administrative authority of IBAMA, which issues operating and drilling licenses. We are required to submit reports, including safety and pollution monitoring reports (IOPP) to IBAMA in order to maintain our licenses. Onshore environmental, health and safety conditions are controlled at the state rather than federal level, and there is strict liability for environmental damage, mechanisms for enforcement of environmental standards and licensing requirements for polluting activities.

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Individuals or entities whose conduct or activities cause harm to the environment are subject to criminal and administrative sanctions. Government environmental protection agencies may also impose administrative sanctions for noncompliance with environmental laws and regulations, including:

- Fines;
- Partial or total suspension of activities;
- Requirements to fund reclamation and environmental projects;
- Forfeiture or restriction of tax incentives or benefits;
- Closing of establishments or operations; and
- Forfeiture or suspension of participation in credit lines with official credit establishments.

We are subject to a number of administrative and legal proceedings relating to environmental matters. See Item 8. "Financial Information—Legal Proceedings." and Note 27 to our audited consolidated financial statements included in this annual report for a description of the legal and administrative proceedings to which we are subject.

In 2012, we invested approximately U.S.$1,498 million in environmental projects, compared to approximately U.S.$1,625 in 2011 and U.S.$1,377 million in 2010. These investments were primarily directed at reducing emissions and wastes resulting from industrial processes, managing water use and effluents, remedying impacted areas, implementing new environmental technologies, upgrading our pipelines and improving our ability to respond to emergency situations.

Health, Safety and Environmental Initiatives

The protection of human health and the environment is one of our primary concerns, and is essential to our success as an integrated energy company.

As a result of an internal reorganization carried out in 2012, we have formalized the existence of an Environmental Committee composed of three members of our board of directors who are responsible for assisting our board the directors in the following matters:

- Definition of strategic goals in relation to environmental matters;
- Establishment of global policies related to the strategic management of environmental matters within Petrobras system;

- Assess the conformity of Petrobras Strategic Plan to its global environmental policies, among others.

Our actions to address health, safety and environmental concerns and ensure compliance with environmental regulations involved an investment of approximately U.S.$2.6 billion in 2012 and included:

- A HSE management system based on principles of sustainable development which seeks to minimize the impacts of operations and products on health, safety and the environment, reduce the use of natural resources and pollution, and prevent accidents;

- ISO 14001 (environment) and OHSAS 18001 (health and safety) certification of our operating units. As of December 2012, Petrobras had 88% of the total number of 295 certifiable sites in Brazil and abroad certified in accordance with the standards mentioned above. All the oil refined in Brazil was processed by certified units. The *Frota Nacional de Petroleiros* (National Fleet of Vessels) has been fully certified by the International Maritime Organization (IMO) International Management Code for Safe Operation of Ships and for Pollution Prevention (ISM Code) since December 1997;

- Regular and active engagement with the MME and IBAMA, in order to discuss environmental issues connected with new oil and gas production and other transportation and logistical aspects of our operations.

- A new strategic goal seeking to maximize energy efficiency and reduce greenhouse gases emission intensity, which was approved by our board of executive officers in November 2010 along with a set of performance indicators with targets to monitor progress with respect to this new challenge. Our objective is to reach excellence levels in the oil and gas industry and to contribute to business sustainability.

- The HSE and Energy Efficiency in Investments project, which began in 2011 and aim at identifying opportunities, risks as well as ensuring the integration of health, safety, environment and energy efficiency (HSEE) aspects throughout the life cycle of new investment projects. Given the high volume of investments planned for the coming years, the project will benefit from the opportunity to increase our HSEE performance with lower marginal costs, contributing to the reduction of losses, to operational continuity and to a lower exposure to penalties and liabilities.

Every investment project is evaluated to confirm its compliance with all HSE requirements and adoption of the best HSE practices throughout the project's life cycle. In addition, we conduct more extensive environmental studies for new projects when required by applicable environmental legislation.

We are committed to reduce greenhouse gas emission intensity from our processes and products, as expressed in our 2020 Strategic Plan. Our strategy focuses on energy efficiency, energy production from renewable sources and research and technological development. This strategy aims both at improving business sustainability and mitigating the effects on climate change.

In 2012, we reduced gas flaring by 60.8% and recovered 91.2% of the associated natural gas produced, outperforming the previous year. By investing U.S.$29 million in energy efficiency projects, in addition to other investments in optimization and reliability, complemented by the introduction of changes in operational procedures, we were able to save 4 mboe/d of gas.

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Environmental Remediation Plans and Procedures

As part of our environmental plans, procedures and efforts, we have developed detailed response and remediation contingency plans to be implemented in the event of an oil spill or leak from our offshore operations. We have more than 600 trained workers available to respond to oil spills 24 hours a day, seven days a week, and we can mobilize additional trained workers for shoreline cleanups on short notice from a group of 5,000 trained environmental agents in the country. While these workers are located in Brazil, they are also available to respond to an offshore oil spill outside of Brazil. We also have stockpiles of the equipment needed to quickly and effectively contain offshore spills or leaks, including over 206 miles of containment and absorbent booms, 481 different oil skimmers, around 60,000 gallons of oil dispersants and 453 oil pumps. Petrobras has 45 dedicated oil spill recovery vessels (OSRVs) fully equipped for oil spill control and fire fighting, as well as 261 additional support and recovery boats and barges available to fight offshore oil spills and leaks 24 hours a day, seven days a week.

We created 10 environmental protection centers in strategic areas in which we operate throughout Brazil in order to ensure rapid and coordinated response to onshore or offshore oil spills. These regional facilities are supported by 13 local advanced bases dedicated to oil spill prevention, control and response. Our environmental protection centers and their advanced bases would be mobilized in the event of a spill or leak at one of our offshore operations. Each of our local and regional response centers is self-sufficient and available to respond either individually or jointly together with neighboring facilities depending on the severity and scale of the emergency.

Our capability to manage major accidents includes the availability of international logistics through sharing agreements with Oil Spill Response Organizations (OSROs). We have contracts signed with local emergency responders Clean Caribbean and Americas Cooperative and Oil Spill Response Limited, in order to ensure a global coverage regarding accidents management. We maintain relationships with other major OSROs and oil companies as well. In addition, we are striving to ensure an appropriate assignment of government and industry roles in the context of major accidents as well as to contribute to the regulation of *in situ* burning operations and the subsea use of chemical dispersants.

In 2012, we conducted 51 emergency drills of regional and national scope with the Brazilian navy, the civil defense, firefighters, the military police, environmental organizations and local governmental and community entities.

We set up a Zero Spill Plan, aiming at optimizing management and reducing the risk of oil spill in our operations. This plan includes actions in the management, process and integrity areas and is currently under implementation in business areas and subsidiary companies.

The adoption of a new model of communication, processing and recording of oil spills made possible the daily monitoring of these incidents, their impacts and mitigation measures.

In 2012, we experienced oil spills totaling 2,436 barrels of crude oil, compared to 1,471 barrels of crude oil in 2011 and 4,200 barrels of crude oil in 2010.

The oil spill level in our upstream operations in 2012 was kept below 0.5 m^3 per mmbbl produced. Data for 2011 compiled by the International Association of Oil & Gas Producers indicates that the industry average was 1.26 m^3 of oil spilled per mmbbl produced. We continue to evaluate and develop initiatives to address HSE concerns and to reduce our exposure to HSE risks.

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Insurance

Our insurance programs focus principally on the evaluation of risks and the replacement value of assets, which is customary for our industry. Under our risk management policy, risks associated with our principal assets, such as refineries, tankers and offshore production units and drilling rigs, are insured for their replacement value with third-party Brazilian insurers. Although some policies are issued in Brazil, most of our policies are reinsured abroad with reinsurers rated A- or higher by Standard & Poor's rating agency or B+ or higher by A.M. Best. Part of our international operations are insured or reinsured by our Bermudian subsidiary BEAR following the same rating criteria.

Less valuable assets, including but not limited to small auxiliary boats, certain storage facilities, and some administrative installations, are self-insured. We do not maintain coverage for business interruption, except for a minority of our international operations and a few specific assets in Brazil. We also do not maintain coverage for our wells for all of our Brazilian operations. Although we do not insure most of our pipelines, we have insurance against damage or loss to third parties resulting from specific incidents, as well as oil pollution. We also maintain coverage for risks associated with cargo, hull and machinery risk. All projects and installations under construction that have an estimated maximum loss above U.S.$80 million are covered by a construction insurance policy.

We have operations in 21 countries outside Brazil and maintain varying levels of third-party liability insurance for our domestic and international operations as a result of a variety of factors, including our country risk assessments, whether we have onshore and offshore operations and legal requirements imposed by the particular country in which we operate. We maintain insurance coverage for operational third-party liability with respect to our onshore and offshore activities, including environmental risks such as oil spills, in Brazil up to an aggregate policy limit of U.S.$250 million for a period of 18 months. We also maintain additional protection and indemnity (P&I) marine insurance against third-party liability related to our domestic offshore operations up to an aggregate policy limit of up to U.S.$500 million for a period of 12 months. In the event of an explosion or similar event at one of our offshore rigs in Brazil, these policies can provide combined third-party liability coverage of up to U.S.$750 million for a period of 12 months.

Our domestic and international operational third-party liability policies cover claims made against us by or on behalf of individuals who are not our employees in the event of personal injury or death, subject to the policy limits set forth above. As a general rule, our service providers are required to indemnify us for a claim we pay directly to a third party as a result of a court decision holding us liable for the actions of that service provider. Our operational third-party liability policies also cover environmental damage from oil spills (including liability arising from an explosion or similar sudden and accidental event at one of our offshore rigs) as well as litigation, clean-up and remediation costs, but do not cover governmental fines or punitive damages.

We maintain separate “control-of-well” insurance policies at our international operations to cover liability arising from the uncontrolled eruption of oil, gas, water or drilling fluid, as well as to cover claims for environmental damage from well blow-outs and similar events as well as related clean-up costs, with aggregate policy limits up to U.S.$500 million for a period of 12 months depending on the country. In the U.S. Gulf of Mexico, for example, we maintain third-party liability coverage up to an aggregate policy limit of U.S.$250 million for a period of 12 months, and control-of-well liability insurance up to U.S.$500 million for a period of 12 months. Depending on the particular circumstances, either of these policies could apply in the event of an explosion or similar event at one of our offshore rigs in the U.S. Gulf of Mexico.

We do not maintain control-of-well insurance for our domestic operations onshore and offshore Brazil. As a result, we would bear the costs of clean-up, decontamination and any proceedings arising out of a control-of-well incident. Any loss of hydrocarbon containment from our domestic operations onshore and offshore that is not attributable to a control-of-well issue would be covered by either our Protection & Indemnity (P&I) insurance, with coverage of up to U.S.$500 million for our mobile offshore units, or our onshore-offshore liability policy, with coverage of up to U.S.$250 million.

The premium for renewing our domestic property risk insurance policy for an 18-month period commencing June 2012 was U.S.$97.5 million. This represented a nominal increase of 12% considering the same preceding 12-month period. The insured value of our assets, in the same period, increased by 17% to U.S.$142.6 billion. The average rate for the period was 0.04567%, representing a decrease of 4.67% relative to the previous period. Since 2001, our risk retention has increased and our deductibles may reach U.S.$80 million in certain cases.

Additional Reserves and Production Information

Production of crude oil and natural gas in Brazil is divided into onshore and offshore production, comprising 11% and 89% of total production in Brazil, respectively. The Campos Basin is one of Brazil's main and most prolific oil and gas offshore basins, with over 60 hydrocarbon fields discovered, eight large oil fields and a total area of approximately 115,000 km^2 (28.4 million acres). In 2012, the Campos Basin produced an average 1,618.3 mbbl/d of oil and 498.5 mmcf/d (13.2 mmm^3/d) of associated natural gas, comprising 77% of our total production from Brazil. We also conduct limited oil shale mining operations in São Mateus do Sul, in the Paraná Basin of Brazil, and we use oil shale from these deposits to produce synthetic oil and gas. Our oil shale industrialization business unit does not utilize the fracking method or the hydraulic fracturing method for purposes of oil production given that they are not proper for this end. We crush and subsequently heat in high temperatures all the shale we produce, obtaining a proper segregation of the products derived from such process. We do not inject any water or chemicals in the soil in connection with our oil shale mining operations.

On December 31, 2012, our estimated proved reserves of crude oil, condensate and natural gas in Brazil totaled 12.3 bnbbl of oil equivalent, including 10.5 bnbbl of crude oil and condensate and 274.1 bnm^3 (10.3 tcf) of natural gas. As of December 31, 2012, our domestic proved developed crude oil and condensate reserves represented 61% of our total domestic proved developed and undeveloped crude oil and condensate reserves, and our domestic proved developed natural gas reserves represented 66% of our total domestic proved developed and undeveloped natural gas reserves. Total domestic proved crude oil and condensate reserves increased at an average annual rate of 3% in the last five years, and total natural gas proved reserves increased at an average annual rate of 1% over the same period.

We calculate reserves based on forecasts of field production, which depend on a number of technical parameters, such as seismic interpretation, geological maps, well tests, reservoir engineering studies and economic data. All reserve estimates involve some degree of uncertainty. The uncertainty depends primarily on the amount of reliable geological and engineering data available at the time of the estimate and the interpretation of that data. Our estimates are thus made using the most reliable data and technology at the time of the estimate, in accordance with the best practices in the oil and gas industry and regulations promulgated by the Securities and Exchange Commission.

Internal Controls over Proved Reserves

The reserves estimation process begins with an initial evaluation of our assets by geophysicists, geologists and engineers. Corporate Reserves Coordinators (*Coordenadores de Reservas Corporativos*, or CRCs) safeguard the integrity and objectivity of our reserves estimates by supervising and providing technical support to Regional Reserves Coordinators (*Coordenadores de Reservas Regionais*, or CRRs) who are responsible for preparing the reserves estimates. Our CRRs and CRCs have degrees in geophysics, geology, petroleum engineering, accounting and economics and are trained internally and abroad in international reserves estimates seminars. CRCs are responsible for compliance with Securities and Exchange Commission rules and regulations, consolidating and auditing the reserves estimation process. The technical person primarily responsible for overseeing the preparation of our domestic reserves is a member of the SPE, with 23 years of experience in the field and has been with Petrobras for 29 years. The technical person primarily responsible for overseeing the preparation of our international reserves is currently the chairman of the SPE—Brazil Section. He has seven years of experience in the field, a doctorate in reservoir engineering and has been with Petrobras for 33 years. Our reserves estimates are presented to our board of executive officers and submitted to the board of directors for final approval.

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DeGolyer and MacNaughton (D&M) used our reserves estimates to conduct a reserves audit of 93% of the net proved crude oil, condensate and natural gas reserves as of December 31, 2012 from certain properties we own in Brazil. In addition, D&M used its own estimates of our reserves to conduct a reserves evaluation of 100% of the net proved crude oil, condensate, NGL and natural gas reserves as of December 31, 2012 from the properties we operate in Argentina. Furthermore, D&M used our reserves estimates to conduct a reserves audit of 98% of the net proved crude oil, condensate and natural gas reserves as of December 31, 2012 from certain properties we operate in North and South America (other than Brazil and Argentina). The reserves estimates were prepared in accordance with the reserves definitions of Rule 4-10(a) of Regulation S-X of the SEC. For further information on our proved reserves, see "Supplementary Information on Oil and Gas Exploration and Production" beginning on page F-90. For disclosure describing the qualification of D&M's technical person primarily responsible for overseeing our reserves audit and reserves evaluation, see Exhibit 99.1.

Changes in Proved Reserves

At year-end 2012 compared to year-end 2011, we added a net total of 588.0 mmboe to our domestic proved undeveloped reserves and 2.4 mmboe to our international proved undeveloped reserves, resulting in a net increase of 590.4 mmboe company-wide. Thus, we had a total of 5,062.2 mmboe of proved undeveloped reserves company-wide at December 31, 2012, compared to 4,471.8 mmboe of proved undeveloped reserves company-wide at December 31, 2011.

In Brazil, the net increase in our proved undeveloped reserves in 2012 compared to 2011 resulted from the 434.4 mmboe of extensions and discoveries in the pre-salt areas of the Santos Basin and in other areas of the Campos Basin, the 180.6 mmboe of technical revisions to previous estimates, the 26.2 mmboe of economic revisions to previous estimates and the 273.3 mmboe of improved recovery. In addition, we converted a net total of 326.6 mmboe of our proved undeveloped reserves to proved developed reserves in Brazil in 2012, mainly through the drilling of several wells in existing production fields.

Outside Brazil, the net increase in our proved undeveloped reserves in 2012 compared to 2011 was mainly due to newly estimated reserves in the United States which was offset by the conversion of 71.3 mmboe of proved undeveloped reserves to proved developed reserves.

All reserves volumes described above are "net" to the extent that they only include Petrobras' proportional participation in reserve volumes and exclude reserves attributed to our partners.

In 2012, we invested a total of U.S.$11.3 billion in development projects, of which approximately 89% (U.S.$10.1 billion) was invested in Brazil.

Most of our investments relates to long term development projects which are developed in phases due to the large volumes and extensions involved and deep and ultra deep water infrastructure and production resources complexity. In these cases, the full development of the reserves related to these investments can exceed five years.

In 2012, we converted a total of 397.9 mmboe of proved undeveloped reserves to proved developed reserves, approximately 82% (326.6 mmboe) of which were Brazilian reserves.

We had a total of 5,062.2 mmboe of proved undeveloped reserves company-wide at year-end 2012, approximately 3% (134.3 mmboe) of which have remained undeveloped for five years or more as a result of several factors affecting development and production, including the inherent complexity of ultra-deepwater developments projects, particularly in Brazil, and constraints in the capacity of our existing infrastructure.

The majority of the 134.3 mmboe of our proved undeveloped reserves that have remained undeveloped for five years or more consist of reserves in the Santos and Campos Basins, for which we are making investments to develop necessary infrastructure.

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The following tables set forth our production of crude oil, natural gas, synthetic oil and synthetic gas by geographic area in 2012, 2011 and 2010:

	Hydrocarbon Pro				
	2012				
	Oil (mbbl/d) (5)	Synthetic Oil (mbbl/d) (4)	Nat. Gas (mmcf/d) (1)	Synthetic Gas (mmcf/d) (1)(4)	Total (mboe/d
Brazil:					
Roncador field(2)	262.8	0.0	101.4	0.0	279.
Other	1,714.3	3.0	1,249.8	1.1	1,925.
Total Brazil	1,977.1	3.0	1,351.3	1.1	2,205.
International:					
South America (outside of Brazil)	76.4	0.0	629.9	0.0	181.
North America	9.0	0.0	18.8	0.0	12.
Africa	51.8	0.0	0.0	0.0	51.
Total International	137.3	0.0	648.7	0.0	245.
Total consolidated production	**2,114.4**	**3.0**	**2,000.0**	**1.1**	**2,450.**
Equity and non-consolidated affiliates:(3)					
South America (outside of Brazil)	6.4	0.0	2.4	0.0	6.
Worldwide production	2,120.8	3.0	2,002.4	1.1	2,457.

(1) Natural gas production figures are the production volumes of natural gas available for sale, excluding flared and reinjected gas and gas consumed in operations.

(2) Roncador field is separately included as it contains more than 15% of our total proved reserves.

(3) Companies in which Petrobras has a minority interest.

(4) We produce synthetic oil and synthetic gas from oil shale deposits in São Mateus do Sul, in the Paraná Basin of Brazil.

(5) Oil production includes LNG and production from extended well tests.

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The following table sets forth our estimated net proved developed and undeveloped reserves of crude oil and natural gas by region as of December 31, 2012.

Estimated Net Proved Developed and Undeveloped Reserves

y			**Reserves**			
	Oil (mmbbl)	**Natural gas (bncf)**	**Total oil and natural gas (mmboe)**	**Synthetic oil (mmbbl)(1)**	**Synthetic gas (bncf)(1)**	**sy c sy (r**
l:						
	6,397.5	6,811.5	7,532.7	8.3	13.3	
side of Brazil)	96.5	414.1	165.6	–	–	
	21.2	25.2	25.4	–	–	
	77.8	35.8	83.7	–	–	
	195.5	**475.1**	**274.7**	–	–	
proved reserves	6,593.0	7,286.6	7,807.4	8.3	13.3	
onsolidated affiliates						
side of Brazil)	12.7	14.6	15.1	–	–	
eloped reserves	6,605.7	7,301.2	7,822.5	8.3	13.3	
ped:						
	4,141.7	3,533.0	4,730.6	–	–	
side of Brazil)	78.9	669.5	190.5	–	–	
	52.8	42.5	59.9	–	–	
	62.4	9.8	64.0	–	–	
	194.2	721.8	314.5	–	–	
proved reserves	4,335.9	4,254.8	5,045.0	–	–	
onsolidated affiliates						
side of Brazil)	11.6	33.2	17.2	–	–	
eveloped reserves	4,347.6	4,288.0	5,062.2	–	–	
rves (developed and undeveloped)	**10,953.3**	**11,589.2**	**12,884.7**	**8.3**	**13.3**	

(1) Volumes of synthetic oil and synthetic gas from oil shale deposits in the Paraná Basin in Brazil have been included in our proved reserves in accordance with the SEC rules for estimating and disclosing reserve quantities.

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The table below summarizes information about the changes in total proved reserves of our consolidated entities for 2012, 2011 and 2010:

Total Proved Developed and Undeveloped Reserves (consolidated entities only)

	Oil (mmbbl)	Natural gas (bncf)	Total oil and natural gas (mmboe)	Synthetic oil (mmbbl)	Sy
ion for the year ended December 31, 2012					
	10,774.2	12,367.8	12,835.5	8.6	
s	112.8	363.8	173.5	0.7	
	343.8	(623.5)	239.9	–	
	–	–	–	–	
	435.8	295.3	485.0	–	
	(738.1)	(862.2)	(881.8)	(1.0)	
	–	–	–	–	
	10,928.5	**11,541.2**	**12,852.1**	**8.3**	
ion for the year ended December 31, 2011					
	10,723.8	11,881.8	12,704.1	7.4	
s	613.6	998.3	780.0	2.4	
	8.0	0.3	8.1	–	
	–	–	–	–	
	168.6	277.7	214.9	–	
	(739.8)	(790.3)	(871.5)	(1.2)	
	–	–	–	–	
	10,774.2	**12,367.8**	**12,835.5**	**8.6**	
ion for the year ended December 31, 2010					
	10,262.2	10,982.5	12,092.6	6.8	
s	375.8	330.9	431.0	1.8	
	29.7	15.1	32.2	–	
	–	–	–	–	
	804.6	1,284.6	1,018.7	–	
	(742.5)	(730.2)	(864.2)	(1.2)	
	(6.0)	(1.1)	(6.2)	–	
	10,723.8	**11,881.8**	**12,704.1**	**7.4**	

Natural gas production volumes used in this table are the net volumes withdrawn from Petrobras' proved reserves, including flared gas consumed in operations and excluding reinjected gas. Oil production volumes used in this table are net volumes withdrawn from Petrobras' proved reserves and exclude LNG and production from extended well tests. As a result, the oil and natural gas production volumes in this table are different from those shown in the production table above, which shows the production volumes of natural gas available for sale.

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We do not have any material acreage expiry before 2025 with respect to our Brazilian onshore and offshore operations. We also do not have any material acreage expiry within the next three years of our leases or concessions with respect to our international operations.

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which Petrobras had interests as of December 31, 2012.

Gross and Net Productive Wells and Gross and Net Developed and Undeveloped Acreage

	As of December 31, 2012						
	Oil		**Natural gas**		**Synthetic oil**		**Synt g**
s and net productive wells:(1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gros**
olidated subsidiaries							
l	8,359	8,355	263	257	0	0	
national							
America (outside of Brazil)	6,477	5,010	388	284	0	0	
America	11	8	5	2	0	0	
	47	9	0	0	0	0	
international	6,535	5,027	393	286	0	0	
consolidated	14,894	13,382	656	543	0	0	
y and non-consolidated affiliates:							
America (outside of Brazil)	422	115	0	0	0	0	
gross and net productive wells	15,316	13,497	656	543	0	0	

	As of December 31, 2012						
	Oil		**Natural gas (in acres)**		**Synthetic oil**		**Synt g**
s and net developed acreage:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gros**
l	4,092,865.4	3,825,801.0	401,748.5	384,994.1	1,346.0	1,346.0	
national							
America (outside of Brazil)	506,989.3	376,518.1	3,118,673.8	2,344,739.4	0	0	
America	10,871.9	7,034.2	16,322.5	6,069.6	0	0	
	362,099.4	56,775.0	0	0	0	0	
international	879,960.6	440,327.3	3,134,996.4	2,350,809.0	0	0	
consolidated	4,972,826.0	4,266,128.3	3,536,744.9	2,735,803.1	1,346.0	1,346.0	
y and non-consolidated affiliates:							
America (outside of Brazil)	127,173.2	29,879.3	9,457.6	3,216.8	0	0	
gross and net developed acreage	5,099,999.2	4,296,007.5	3,546,202.5	2,739,019.9	1,346.0	1,346.0	

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	As of December 31, 2012						
	Oil		Natural gas (in acres)		Synthetic oil		Synth gas
ss and net undeveloped acreage:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**
zil	932,389.0	753,223.0	262,322.1	260,549.7	0	0	0
ernational							
th America (outside of Brazil)	167,624.6	122,641.8	2,195,260.1	1,148,853.6	0	0	0
th America	9,531.5	6,392.8	8,649.4	5,645.5	0	0	0
ca	282,475.0	46,575.7	0	0	0	0	0
al international	459,631.1	175,610.3	2,203,909.5	1,154,499.2	0	0	0
al consolidated	1,392,020.1	928,833.3	2,466,231.6	1,415,048.9	0	0	0
ity and non-consolidated affiliates:							
th America (outside of Brazil)	278,176.3	68,113.3	70,307.7	22,877.7	0	0	0
al gross and net undeveloped acreage	1,670,196.3	996,946.6	2,536,539.3	1,437,926.6	0	0	0

A “gross” well or acre is a well or acre in which a working interest is owned, while the number of “net” cres is the sum of fractional working interests in gross wells or acres.

The following table sets forth the number of net productive and dry exploratory and development wells drilled for the last three years.

Net Productive and Dry Exploratory and Development Wells

	2012	2011	2010
Net productive exploratory wells drilled:			
Consolidated subsidiaries:			
Brazil	44.7	31.9	60.1
South America (outside of Brazil)	4.0	3.3	3.7
North America	1.1	0.6	0.0
Africa	0.0	0.2	0.2
Other	0.0	0.0	0.7
Total consolidated subsidiaries	49.8	36.0	64.7
Equity and non-consolidated affiliates:			
South America (outside of Brazil)	0.4	0.0	0.0
Total productive exploratory wells drilled	50.2	36.0	64.7

Net dry exploratory wells drilled:

Consolidated subsidiaries:			
Brazil	42.2	50.8	39.5
South America (outside of Brazil)	3.0	0.9	2.6
North America	0.5	0.0	0.0
Africa	0.7	0.5	1.7
Other	0.0	0.0	0.0
Total consolidated subsidiaries	46.4	52.2	43.8
Equity and non-consolidated affiliates:			
South America (outside of Brazil)	0.0	0.0	0.0
Total dry exploratory wells drilled	46.4	52.2	43.8
Total number of net wells drilled	96.6	88.2	108.5
Net productive development wells drilled:			
Consolidated subsidiaries:			
Brazil	355.1	228.0	457.5
South America (outside of Brazil)	239.9	194.2	179.6
North America	1.8	0.0	1.1
Africa	0.6	0.4	1.3
Other	0.0	0.0	0.0
Total consolidated subsidiaries	597.4	422.6	639.5
Equity and non-consolidated affiliates:			
South America (outside of Brazil)	2.4	3.0	4.0

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The following table summarizes the number of wells in the process of being drilled as of December 31, 2012. For more information about our on-going exploration and production activities in Brazil, see "—Exploration and Production." Our present exploration and production activities outside of Brazil are described in "—International."

Number of Wells Being Drilled as of December 31, 2012

	Year-end 2012	
	Gross	**Net**
Wells Drilling		
Consolidated Subsidiaries:		
Brazil	93.0	75.1
International:		
South America (outside of Brazil)	12.0	6.9
North America	3.0	1.9
Africa	1.0	0.2
Others	0.0	0.0
Total International	16.0	9.0
Total consolidated production	109.0	84.1
Equity and non-consolidated affiliates:		
South America (outside of Brazil)	0.0	0.0
Total wells drilling	109.0	84.1

(1) Includes 155 wells with multiple completions.

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The following table sets forth our average production prices and average production costs by geographic area and by product type for the last three years.

	Brazil	South America (outside of Brazil)	North America	Africa	Total	Equity and non-consolidated affiliates(2)
				(U.S.$)		
During 2012						
Average production prices						
Oil, per barrel	104.60	81.53	100.56	112.15	103.90	89.73
Natural gas, per thousand cubic feet(1)	8.63	3.37	3.17	–	7.75	–
Synthetic oil, per barrel	99.13	–	–	–	99.13	–
Synthetic gas, per thousand cubic feet	7.33	–	–	–	7.33	–
Average production costs, per barrel – total	13.75	13.71	6.69	9.39	13.62	22.80
During 2011						
Average production prices						
Oil, per barrel	102.24	74.03	107.02	114.65	101.52	89.40
Natural gas, per thousand cubic feet(1)	9.43	3.16	4.72	–	8.27	–
Synthetic oil, per barrel	98.94	–	–	–	98.94	–
Synthetic gas, per thousand cubic feet	7.42	–	–	–	7.42	–
Average production costs, per barrel – total	13.08	12.61	12.43	6.29	12.89	14.57
During 2010						
Average production prices						
Oil, per barrel	74.66	57.17	74.53	79.44	74.12	75.54
Natural gas, per thousand cubic feet(1)	7.34	2.55	4.56	–	6.49	–
Synthetic oil, per barrel	66.78	–	–	–	66.78	–
Synthetic gas, per thousand cubic feet	7.06	–	–	–	7.06	–
Average production costs, per barrel – total	11.11	8.83	23.03	3.15	10.78	15.18

(1) The volumes of natural gas used in the calculation of this table are the production volumes of natural gas available for sale and are also shown in the production table above. Natural gas amounts were converted from bbl to cubic feet in accordance with the following scale: 1 bbl = 5.6146 cubic feet.

(2) Operations in Venezuela.

Item 4A. Unresolved Staff Comments

Not applicable.

Item 5. Operating and Financial Review and Prospects

Management's Discussion and Analysis of Financial Condition and Results of Operations

The information derived from our financial statement as of and for the years ended December 31, 2012, 2011 and 2010 has been prepared in accordance with IFRS issued by the IASB. For more information, see "Presentation of Financial and Other Information" and Note 2 to our audited consolidated financial statements.

You should read the following discussion of our financial condition and results of operations together with our audited consolidated financial statements and the accompanying notes beginning on page F-2 of this annual report.

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Overview

We earn income from:

- domestic sales, which consist of sales of oil products (such as diesel, gasoline, jet fuel, naphtha, fuel oil and liquefied petroleum gas), natural gas, ethanol, electricity and petrochemical products;
- export sales, which consist primarily of sales of crude oil and oil products;
- international sales (excluding export sales), which consist of sales of crude oil, natural gas and oil products that are purchased, produced and refined abroad; and
- other sources, including services, investment income and foreign exchange gains.

Our expenses include:

- costs of sales (which are composed of labor expenses, operating costs and purchases of crude oil and oil products); maintaining and repairing property, plant and equipment; depreciation and amortization of fixed assets; depletion of oil fields; and exploration costs;
- selling (which include expenses for transportation and distribution of our products), general and administrative expenses;
- research and development and other operating expenses; and
- interest expense, monetary and foreign exchange losses.

Fluctuations in our financial condition and results of operations are driven by a combination of factors, including:

- the volume of crude oil, oil products and natural gas we produce and sell;
- changes in international prices of crude oil and oil products, which are denominated in U.S. dollars;
- related changes in the domestic prices of crude oil and oil products, which are denominated in *reais*;
- the demand for oil products in Brazil, and the amount of imports required to meet that demand;
- fluctuations in the *real*/U.S. dollar and to a lesser degree, Argentine peso/U.S. dollar exchange rates; and

- the amount of production taxes that we are required to pay with respect to our operations.

Sales Volumes and Prices

The profitability of our operations in any particular accounting period is related to the sales volume of, and prices for, the crude oil, oil products, natural gas and biofuels that we sell. Our consolidated net sales in 2012 totaled approximately 1,385,917 thousand barrels of crude oil equivalent, representing U.S.$144,103 million in sales revenues, compared to 1,355,309 thousand barrels of crude oil equivalent, representing U.S.$145,915 million in sales revenues in 2011, and approximately 1,332,205 thousand barrels of crude oil equivalent, representing U.S.$120,452 million in sales revenues in 2010.

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As a vertically integrated company, we process most of our crude oil production in our refineries and sell the refined oil products primarily in the Brazilian domestic market. Therefore, it is oil product prices in Brazil, rather than crude oil prices, that most directly affect our financial results. International oil product prices vary over time as the result of many factors, including the price of crude oil. Over the long term, we intend to sell our products in Brazil at parity with international product prices, however we do not adjust our prices for all gasoline, diesel and other products to reflect short-term volatility in the international markets. As a result, material rapid or sustained increases or decreases in the international price of crude oil and oil products may result in downstream margins for us that are materially different than those of other integrated international oil companies, within a given financial reporting period.

The average prices of Brent crude, an international benchmark oil, were approximately U.S.$111.58 per barrel in 2012, U.S.$111.27 per barrel in 2011 and U.S.$79.47 per barrel in 2010. In December 2012, Brent crude oil prices averaged U.S.$109.35 per barrel. However, due to the devaluation of the Brazilian *real* throughout the year of 2012, the price of the Brent crude, when expressed in Brazilian *reais*, went from R$197.89 per barrel in December 31, 2011 to R$227.22 per barrel in December 31, 2012.

In November 2011, we announced price increases at the refinery gate (the wholesale price we sell to distributors) of 10% for gasoline and 2% for diesel to partially adjust to higher international oil product prices. During 2012, we announced further price increases at the refinery gate totaling 7.8% for gasoline and 10.2% for diesel when compared to December 31, 2011 prices. The effect of these price increases to retail customers was partially offset by the reduction by the Brazilian federal government of the CIDE tax rate for gasoline and diesel, that currently is reduced to 0% for both oil products. Until April 25, 2013, we have announced price increases of 6.6% for gasoline and 10.7% for diesel, when compared to December 31, 2012. These price adjustments were implemented by the Company pursuant to its stated pricing policy, which seeks to align the price of oil products with the international market in the long-term.

During 2012, approximately 69.7% of our sales revenues were derived from sales of oil products, natural gas and other products in Brazil, compared to 67.8% in 2011 and 68.5% in 2010.

For the Year Ended December 31,								
	2012			2011			2010	
Volume (mbbl, except as otherwise	Net Average Price (U.S.$) (1)	Sales Revenues (U.S.$ million)	Volume (mbbl, except as otherwise	Net Average Price (U.S.$) (1)	Sales Revenues (U.S.$ million)	Volume (mbbl, except as otherwise	Net Average Price (U.S.$) (1)	S Rev (U mi

	noted)			**noted)**			**noted)**		
	343,063	112.39	38,558	321,106	123.09	39,524	295,297	113.07	
otive	208,695	111.54	23,277	178,471	122.96	21,945	143,947	110.13	
e									
ng									
fuel)	30,896	92.71	2,864	29,813	97.81	2,916	36,481	85.45	
a	60,331	95.23	5,745	61,034	94.18	5,748	61,111	62.32	
ed	81,992	50.32	4,126	81,636	59.85	4,886	79,695	55.90	
um gas									
	38,896	150.72	5,862	37,010	148.71	5,504	32,965	132.24	
il	72,969	81.67	5,959	68,780	98.83	6,797	65,663	85.44	
ts									
al oil	**836,842**	**–**	**86,393**	**777,849**	**–**	**87,320**	**715,160**	**–**	
cts									
gas	130,544	50.41	6,580	110,042	51.80	5,701	113,834	25.47	
,									
n									
ts,									
bles									
er									
ts	30,369	132.60	4,027	31,413	141.56	4,447	36,154	106.40	
ity,									
s and									
	–	–	3,498	–	–	1,473	–	–	
	997,755	**–**	**100,498**	**919,305**	**–**	**98,941**	**865,147**	**–**	
tic									
t									
net	203,234	109.99	22,353	231,086	106.66	24,649	255,125	74.73	
tional	184,928	114.92	21,253	204,919	108.95	22,325	211,932	88.82	
es									
	388,162	**–**	**43,606**	**436,004**	**–**	**46,973**	**467,057**	**–**	
ational									
t									
idated	**1,385,917**	**–**	**144,103**	**1,355,309**	**–**	**145,915**	**1,332,205**	**–**	**1**
ues									

(1) Net average price calculated by dividing sales revenues by the volume for the year.

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Effect of Taxes on Our Income

In addition to taxes paid on behalf of consumers to federal, state and municipal governments, such as the Domestic value-added tax (*Imposto sobre Circulação de Mercadorias e Serviços*, or ICMS), we are required to pay three principal charges on our oil production activities in Brazil: royalties, special participation and retention bonuses. See Item 4. “Information on the Company—Regulation of the Oil and Gas Industry in Brazil—Taxation under Concession Regime for Oil and Gas” and Item 3. “Key Information—Risk Factors—Risks Relating to Brazil.”

These charges imposed by the Brazilian federal government are included in our cost of goods sold. In addition, we are subject to tax on our income at an effective rate of 25% and a social contribution tax at an effective rate of 9%, the standard corporate tax rate in Brazil. See Note 19.3 to our audited consolidated financial statements for the year ended December 31, 2012.

Inflation and Exchange Rate Variation

Inflation

Since the introduction of the *real* as the Brazilian currency in July 1994, inflation in Brazil has remained relatively stable. Inflation was 5.84% in 2012, 6.50% in 2011 and 5.90% in 2010 as measured by IPCA, the National Consumer Price Index. Inflation has had, and may continue to have, effects on our financial condition and results of operations.

Exchange Rate Variation

Our functional currency is the Brazilian *real* and our presentation currency is the U.S. dollar. Therefore, we maintain our financial records in *reais*, and translate our financial statements into U.S. dollars for presentation purposes based on the average exchange rates prevailing during the period or at the balance sheet date, pursuant to the criteria set out in IAS 21 - “The effects of changes in foreign exchange rates”. Fluctuations in exchange rate have multiple effects in our results of operations. Although a substantial portion of our revenues is in *reais*, our revenues are derived from products with U.S. dollar-based international prices, since virtually all of our sales are of crude oil or oil products.

From 2003 to 2011, considering the average exchange rates prevailing throughout the year, the U.S. dollar depreciated against the *real*, except in 2009. In 2012, the U.S dollar appreciated 14.3% against the *real*, compared to a depreciation of 5.1% in 2011 and 13.5% in 2010.

When the *real* appreciates relative to the U.S. dollar the effect is to generally increase both revenues and expenses when expressed in U.S. dollars. When the *real* depreciates relative to the U.S. dollar the effect is to generally decrease revenues and expenses when expressed in U.S. dollars.

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The relative pace at which our total revenues and expenses in *reais* increase or decrease with the exchange rate, and its impact upon our margins, is affected by our pricing policy in Brazil. When the *real* appreciates against the U.S. dollar and we do not adjust our price in Brazil, our margins generally improve. When the *real* depreciates against the U.S. dollar and we do not adjust our prices, margins generally decline.

Exchange rate variation also affects the amount of retained earnings available for distribution by us when expressed in U.S. dollars. Amounts reported as available for distribution in our statutory accounting records are calculated in *reais* and prepared in accordance with the IFRS and they may increase or decrease when expressed in U.S. dollars as the *real* appreciates or depreciates against the U.S. dollar. The foreign exchange variations on foreign-denominated assets and liabilities of Brazilian operations (71% of non-current debt in December 2012) are recorded in the statement of income while the foreign exchange variations on the translation of foreign subsidiaries are recognized in shareholders’ equity. As our net debt increases, the negative impact of a depreciation of the *real* on our results and net income when expressed in *reais* also increases, thereby reducing the earnings available for distribution. In addition, the exchange rate variation creates foreign exchange gains and losses that are included in our results of operations determined in accordance with IFRS and that affect the amount of our unretained earnings available for distribution.

Results of Operations

The differences in our operating results from year to year occur as a result of a combination of factors, including primarily: the volume of crude oil, oil products and natural gas we produce and sell; the price at which we sell our crude oil, oil products and natural gas; the level and cost of imports and exports needed to satisfy our demand; production taxes; and the differential between Brazilian and international inflation rates, adjusted by the depreciation or appreciation of the *real* against the U.S. dollar.

The table below shows the amount by which each of these variables has changed during the last three years. Production volumes presented in this table are prepared in accordance with Society of Petroleum Engineers (SPE) criteria, which are the criteria we apply to analyze our operating results:

	2012	**2011**	**2010**
Crude oil and NGL production (mbbl/d):			
Brazil	1,980	2,022	2,004
International	139	140	144
Non-consolidated international production(1)	7	8	8
Total crude oil and NGL production	**2,126**	**2,170**	**2,156**
Change in crude oil and NGL production	(2.0)%	0.6%	2.0%
Average sales price for crude (U.S.$/barrel):			
Brazil	104.60	102.24	74.66
International	94.37	91.37	66.42
Natural gas production (mmcf/d):			
Brazil	2,250	2,130	2,004
International	582	582	558
Total natural gas production	**2,832**	**2,712**	**2,562**
Change in natural gas production (sold only)	4.4%	5.9%	3.4%
Average sales price for natural gas (U.S.$/mcf):			
Brazil(2)	8.63	9.43	7.34
International	3.00	2.88	2.36
Year-end exchange rate (*Reais*/U.S.$)	2.04	1.88	1.67
Appreciation (depreciation) during the year(3)	(8.5)%	(12.6)%	4.3%
Average exchange rate for the year (*Reais*/U.S.$)	1.96	1.67	1.76
Appreciation (depreciation) during the year(4)	(14.3)%	5.1%	13.5%
Inflation rate (IPCA)	5.8%	6.5%	5.9%

(1) Non-consolidated companies in Venezuela.

(2) Amounts were converted from bbl to cubic feet in accordance with the following scale: 1 bbl = 5.6146 cubic feet.

(3) Based on year-end exchange rate (U.S.$/R$).

(4) Based on average exchange rate for the year (U.S.$/R$).

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Results of Operations—2012 compared to 2011

Virtually all of our revenues and expenses for our Brazilian operations are denominated and payable in Brazilian *reais*. When the U.S. dollar strengthens relative to the Brazilian *real*, as it did in 2012 (with an appreciation of 14.3%), revenues and expenses decrease when translated into U.S. dollars. The appreciation of the U.S. dollar against the Brazilian *real* affects the line items discussed below in different ways. As a consequence, the following comparison between our results of operations in 2012 and in 2011 is impacted by the depreciation of the *real* against the U.S. dollar during that period. See Note 2 of our audited consolidated financial statements for the year ended December 31, 2012, for more information about the translation of Brazilian *real* amounts into U.S. dollars.

Sales Revenues

Sales revenues decreased by 1% to U.S.$144,103 million in 2012 compared to U.S.$145,915 million in 2011. This decrease was principally a result of the appreciation of the U.S. dollar against the Brazilian *real*.

Excluding foreign currency exchange effects, local currency sales revenues increased by 15%, driven by:

- Higher domestic prices for oil products due to increased gasoline and diesel prices and to the impact of the appreciation of the U.S. dollar against the Brazilian *real* on oil products (mainly jet fuel) that were adjusted to reflect international prices; and

- An 8% increase in domestic sales volumes, mainly attributable to the increase of sales volumes of gasoline (17%), diesel (6%), jet fuel (5%) and natural gas (17%), partially offset by lower crude oil exports volumes due to higher feedstock processed and to the lower crude oil production.

Cost of Sales

Cost of sales increased by 8% to U.S.$107,534 million in 2012 compared to U.S.$99,595 million in 2011.

Excluding foreign currency exchange effects, local currency cost of sales increased by 26%, driven by:

- An 8% increase in domestic sales volumes of oil products, mainly met by higher import volumes;

- Higher crude oil and oil products import costs due to higher import volumes, as well as higher production costs;

- Higher depreciation, depletion and amortization costs due to the operational start-up of new facilities;

Selling Expenses

Selling expenses decreased by 8% to U.S.$4,927 million in 2012 compared to U.S.$5,346 million in 2011 due to the appreciation of the U.S. dollar against the Brazilian *real*.

Excluding foreign currency exchange effects, selling expenses increased by 7% in 2012 compared to 2011, primarily as a result of higher freight costs driven by the increase of sales volumes.

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Administrative and General Expenses

Administrative and general expenses decreased by 2% to U.S.$5,034 million in 2012 compared to U.S.$5,161 million in 2011.

Excluding foreign currency exchange effects, administrative and general expenses increased by 14% in 2012 compared to 2011. This increase was principally a result of higher employee compensation expenses arising from the 2011 and 2012 Collective Bargaining Agreements, a larger workforce and increased third-party technical services.

Exploration Costs

Exploration costs increased by 52% to U.S.$3,994 million in 2012 compared to U.S.$2,630 million in 2011. This increase was primarily attributable to higher write-offs of dry or sub-commercial wells.

Research and Development Expenses

Research and development expenses decreased by 21% to U.S.$1,143 million in 2012 compared to U.S.$1,454 million in 2011. This decrease was principally a result of the appreciation of the U.S. dollar. Excluding foreign currency exchange effects, R&D expenses decreased by 8%, due to lower costs with the submarine water-oil separation project (SSAO) in 2012.

Other Operating Income and Expenses, Net

Other operating expenses, net increased by 5% to U.S.$4,185 million in 2012 compared to U.S.$3,984 million in 2011. This increase was principally a result of higher costs due to increased losses on legal and administrative proceedings.

Net finance income (expense)

Net finance expense reached U.S.$1,926 million in 2012, compared to a net finance income of U.S.$76 million in 2011. This decrease was principally a result of the effect of the appreciation of the U.S. dollar against the *real* over a higher net debt.

Non-Controlling Interests

Non-controlling interests decreased to U.S.$103 million in 2012 compared to U.S.$129 million in 2011.

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Net Income (Loss) by Business Segment

We measure performance at the segment level on the basis of net income. The following is a discussion of the net income of our six business segments at December 31, 2012, compared to December 31, 2011.

	Year Ended December 31,		
	2012(1)	**2011(1)**	**Percentage Change**
	(U.S.$ million)		**(%)**
Exploration and Production	23,406	24,326	(3.8)
Refining, Transportation and Marketing	(11,718)	(5,718)	104.9
Gas and Power	861	1,862	(53.8)
Biofuel	(112)	(95)	17.9
Distribution	914	774	18.1
International	719	1,179	(39.0)
Corporate(2)	(2,565)	(721)	255.8
Eliminations	(471)	(1,486)	(68.3)
Net income	**11,034**	**20,121**	**(45.2)**

(1) Excluding non-controlling interests.

(2) Our Corporate segment comprises our financing activities not attributable to other segments, including corporate financial management, central administrative overhead and actuarial expenses related to our pension and medical benefits for inactive participants.

Exploration and Production

Our Exploration and Production segment includes our exploration, development and production activities in Brazil, sales and transfers of crude oil in domestic and foreign markets, transfers of natural gas to our Gas and Power segment and sales of oil products produced at natural gas processing plants.

Exploration and Production net income decreased by 3.8% due to the appreciation of the U.S. dollar against the *real*.

Excluding foreign currency exchange effects, local currency net income on exploration and production increased by 12%, due to increased domestic crude oil prices (sales/transfer), reflecting the depreciation of the *real* against the U.S. dollar and lower impairment charges. These effects were partially offset by lower production levels, higher maintenance and repair costs related to wells, freight costs for oil platforms, depreciation of equipment and production taxes due to the start-up of new systems/wells, as well as by higher write-offs of dry or sub-commercial wells mainly drilled between 2009 and 2012 (at higher costs), especially in areas of new exploratory frontiers.

The spread between the average domestic oil price (sale/transfer) and the average Brent price diminished from US$9.03/bbl in 2011 to US$6.98/bbl in 2012.

See Item 4. “Information on the Company—Overview of the Group—Changes in Proved Reserves” for information on changes in proved reserves.

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Refining, Transportation and Marketing

Our Refining, Transportation and Marketing segment, or RTM, comprises refining, logistics, transportation, export and the purchase of crude oil, as well as the purchase and sale of oil products and ethanol. Additionally, this segment includes the petrochemical division, which comprises investments in domestic petrochemical companies and also extraction and processing of shale. RTM purchases crude oil from E&P and imports oil to blend with our domestic oil. Additionally, RTM purchases oil products in the international markets to meet excess product demand in the domestic market. RTM acquires crude oil and oil products at the international price, either from E&P or from international markets, and sells products in Brazil at a price that we expect will equal international prices in the long run. For some of our products, principally gasoline, diesel and residential LPG, however, the prices in Brazil can lag the international markets. Depending on the impact of this lag effect, RTM's earnings may differ from international refining margins.

Our RTM segment net losses increased by 104.9% due to the impact of the appreciation of the U.S. dollar on crude oil costs (acquisition/transfer) and oil product costs (imports), and also due to higher oil product import volumes (mainly gasoline and diesel). These effects were partially offset by an increase of 7% in export sales prices and a 5% increase in oil product outputs. Excluding foreign currency exchange effects, domestic sales prices increased by 11% in 2012.

Gas and Power

Our Gas and Power segment covers activities of transportation and trading of natural gas produced in or imported into Brazil, transportation and trading of LNG, generation and trading of electric power, as well as corporate interests in local natural gas distribution companies, natural gas transportation companies and in thermoelectric power stations in Brazil, and fertilizer business.

Our Gas and Power segment net income decreased by 53.8% due to lower margins on natural gas sales, driven by the impact of the appreciation of the U.S. dollar on LNG import costs and higher LNG imports volumes to meet the domestic thermoelectric increased demand, and also by the positive impact of tax credits in 2011 (U.S.$554 million). These effects were partially offset by higher average electricity prices and increased sales volumes, attributable to lower water reservoir levels at the hydroelectric power plants located in Brazil, driven by lower rainfall levels in all Brazilian regions.

Biofuel

Our Biofuel segment covers activities of production of biodiesel and its co-products and ethanol activities, through equity investments, production and marketing of ethanol, sugar and the excess electric power generated from sugarcane bagasse.

Our biofuel operations net losses increased by 17.9% due to the negative results of invested companies in the ethanol sector and by an increase in research and development expenses, mainly related to second generation ethanol. The net losses on biofuel operations in 2012 were partially offset by the positive effect of the changes in biodiesel auction rules in the fourth quarter of 2011.

Distribution

Our Distribution segment comprises the oil products, ethanol and compressed natural gas distribution activities conducted mainly by our 100% owned subsidiary, Petrobras Distribuidora S.A. – BR, in Brazil.

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Our Distribution segment net income increased by 18.1% mainly due to an increase in sales margins in 2012 compared with 2011. Our gross margins improved in 2012 because we did not experience the negative factors that affected our margins in 2011, mainly related to losses resulting from the sale of inventory due to the volatility of the ethanol prices, and to a 4% increase in sales volumes, as well as improved operational efficiency.

The Distribution segment accounted for 38.1% of the sales volume of the national fuel distribution market in 2012, compared to 39.2% in 2011.

International

Our International segment comprises our activities in countries other than Brazil, which include exploration and production, refining, transportation and marketing, distribution and gas and power.

Our International segment net income decreased by 39% mainly due to impairment losses (that amounted to U.S.$225 million) in the Pasadena refinery in the United States.

Results of Operations—2011 compared to 2010

Virtually all of our revenues and expenses for our Brazilian activities are denominated and payable in *reais*. When the *real* appreciates relative to the U.S. dollar, as it did in 2011 (an appreciation of 5.1%) the effect is to generally increase both revenues and expenses when expressed in U.S. dollars. However, the appreciation of the *real* against the U.S. dollar affects the line items discussed below in different ways. As a consequence, the following comparison between our results of operations in 2011 and in 2010 is impacted by the appreciation of the *real* against the U.S. dollar during that period. See Note 2.3 of our audited consolidated financial statements for the year ended December 31, 2011, for more information about the translation of Brazilian *real* amounts into U.S. dollars.

Sales Revenues

Sales revenues increased 21% to U.S.$145,915 million in 2011 compared to U.S.$120,452 million in 2010. This increase was primarily a result of:

- increase of 40% in the international Brent crude oil and oil products prices, which resulted in an increase of the prices of exports, international sales, trading operations and domestic oil products indexed to such international prices;

- increase of 10% in domestic gasoline prices and 2% in diesel prices in November 2011;

- increase of 6% in domestic demand, 24% in domestic demand for gasoline, reflecting gasoline's competitive advantage if compared to ethanol, 9% in domestic demand for diesel and 12% in domestic demand for jet fuel; and

- increase of 2% in oil and gas production in Brazil.

These effects were partially offset by a decrease in exports of crude oil due to increased domestic feedstock processed by refineries.

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Cost of Sales (Excluding Depreciation, Depletion and Amortization)

Cost of sales in 2011 increased 29% to U.S.$99,595 million compared to U.S.$77,145 million in 2010. This increase was principally a result of:

- increase of 40.4% (U.S.$8,925 million) in the cost of imports, primarily due to the increase of 6% in domestic demand. The growth in domestic demand was met by higher crude oil and oil products import volumes to support the domestic market, purchased at prevailing international prices, which increased during the year.

- increase of 38.4% (U.S.$4,150 million) in production taxes and charges in 2011 compared to 2010, reflecting higher international oil benchmark prices upon which such taxes and charges are based. The principal production taxes and charges are as follows:

  - royalties, which increased from U.S.$5,340 million in 2010 to U.S.$7,318 million in 2011, an increase of 37% in 2011 as compared to 2010; and

  - special participation charge (a charge payable in the event of high production or profitability from our fields), which increased from U.S.$5,395 million in 2010 to U.S.$7,562 million in 2011, an increase of 40.2% in 2011 as compared to 2010.

The increase in production taxes and charges in 2011 was due to an increase of 40.2% in the reference price for domestic oil, which averaged U.S.$100.39 for 2011 compared to U.S.$71.58 for 2010, reflecting the increase in average prices for crude oil on the international market.

General and Administrative Expenses

General and administrative expenses increased 16% to U.S.$5,161 million in 2011 compared to U.S.$4,441 million in 2010. This increase was primarily attributable to higher personnel expenses due to salary increases arising out of the Collective Bargaining Agreement for 2011, as well as by a larger workforce, higher personnel training costs and increased third-party technical services.

Exploration Costs

Exploration costs increased 21% to U.S.$2,630 million in 2011 compared to U.S.$2,168 million in 2010, due to an increase in the operational activity and higher write-off amounts of dry wells in Brazil.

Research and Development Expenses

Research and development expenses increased 47% to U.S.$1,454 million in 2011 compared to U.S.$989 million in 2010. This higher expense was primarily related to the development of the technological project called *Sistema de Separação Submarina de Água e Óleo – SSAO* (System of Submarine Separation of Water from Oil) and to the increased number of projects with institutions approved by the ANP, pursuant to ANP Rule 5/2005.

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Other Operating Income and Expenses, Net

Other operating income and expenses, net remained relatively constant in 2011 (U.S.$3,984 million) compared to 2010 (U.S.$3,965 million). Excluding the impact of the appreciation of the *real*, other operating income and expenses, net decreased 6% in 2011 compared to 2010, mainly due to:

- U.S.$619 million decrease in losses from legal and administrative proceedings, to U.S.$412 million in 2011 compared to U.S.$1,031 million in 2010; and

- U.S.$542 million in gains from legal and arbitral proceedings in 2011, generated by the recovery of COFINS tax amounts and also as a result of the indemnification related to the assembly of Platform P-48.

This effect was partially offset by the U.S.$331 million increase in impairment losses, to U.S.$369 million in 2011 compared to U.S.$38 million in 2010. See Note 12.4 of our consolidated financial statements for the year ended December 31, 2011.

Financial Income (Expenses), Net

We derive financial income from several sources, including interest income on cash and cash equivalents. The majority of our cash equivalents are short-term Brazilian federal government securities, including securities indexed to the U.S. dollar. We also hold U.S dollar deposits. As we have increased the levels of our indebtedness substantially to fund our investments, the effect of the capitalization of our borrowing costs have had, and will continue to have, a significant impact on our financial result.

Financial income (expenses), net decreased 95% to U.S.$76 million in 2011 compared to U.S.$1,551 million in 2010.

Our net financial income is principally a result of the following factors:

- Our net financial income is also affected by exchange rate movements and the amount of net assets or liabilities subject to exchange rate variation. In 2011 we had net liabilities in *reais* subject to exchange rate variation. Additionally, the value of the *real* against the U.S. dollar decreased 12.6% in 2011, compared to an increase of 4.3% in the value of the *real* against the U.S. dollar in 2010. As a result, exchange rate movements on our debt generated an exchange variation expense of U.S.$2,443 million in 2011 compared to an exchange variation gain of U.S.$800 million in 2010.

- Financial income increased by 56% (U.S.$1,408 million) in 2010 to U.S.$3,943 million in 2011 compared to U.S.$2,535 million in 2010. Most of our cash equivalents are short-term Brazilian federal government securities which earn interest based on the Selic rate. In 2011 the Selic rate was 11.67% compared to 9.82% in 2010. Higher cash and equivalents denominated in *reais* also contributed to the higher interest income.

For a breakdown of our financial income (expenses), net and other additional information, please refer to Notes 27 and 4.6 of our consolidated financial statements for the year ended December 31, 2011.

Non-Controlling Interests

Non-controlling interests increased to a gain of U.S.$129 million in 2011 compared to a loss of U.S.$394 million in 2010, primarily due to the effects of exchange rates over the debt of our Special Purpose Entities – SPE.

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Income Taxes

Income taxes expenses decreased 1.4% to U.S.$6,732 million for 2011 compared to U.S.$6,825 million for 2010 primarily due to the decrease of taxable income. The reconciliation between the tax calculated based upon statutory tax rates to income tax expense and effective rates is set forth in Note 20 of our consolidated financial statements for the year ended December 31, 2011.

Net Income (Loss) by Business Segment

We measure performance at the segment level on the basis of net income. The following is a discussion of the net income of our six business segments at December 31, 2011, compared to December 31, 2010.

	Year Ended December 31,		
	2011(1)	**2010(1)**	**Percentage Change**
	(U.S.$ million)		**(%)**
Exploration and Production	24,326	16,874	44.2
Refining, Transportation and Marketing	(5,718)	2,088	(373.9)
Gas and Power	1,862	736	153.0
Biofuel(2)	(95)	(53)	79.2
Distribution	774	710	9.0
International	1,179	730	61.5
Corporate(2)(3)	(721)	(527)	36.8
Eliminations	(1,486)	(503)	195.4
Net income	**20,121**	**20,055**	**0.3**

(1) Excluding non-controlling interests.

(2) As of 2011, the results of our Biofuel segment have been presented separately from our Corporate segment. The 2010 and 2009 financial information related to our Corporate and Biofuel segments were reclassified accordingly.

(3) Our Corporate segment comprises our financing activities not attributable to other segments, including corporate financial management, central administrative overhead and actuarial expenses related to our pension and medical benefits for inactive participants.

Exploration and Production

The increase of 44% in net income for our Exploration and Production segment was primarily due to an increase of 37% in domestic oil sale/transfer prices and, to a minor extent, an increase of 1% in oil and NGL production, partially offset by increased expenses related to production taxes.

The spread between the average domestic oil sale/transfer price and the average Brent price widened from US$ 4.81/bbl in 2010 to US$ 9.03/bbl in 2011. As a producer of relatively heavy oil, on average, this reduced our income relative to the increase in the Brent price.

See Item 4. “Information on the Company—Overview of the Group—Changes in Proved Reserves” for information on changes in proved reserves.

Refining, Transportation and Marketing

The decrease in net income for our RTM segment was attributable to higher oil acquisition/transfer costs and a greater volume and higher prices of oil product imports, reflecting the increase of 40% in Brent crude oil prices on a U.S.$/bbl basis, which was not fully offset by increasing prices in the domestic and international market during the period.

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Gas and Power

The increase in net income for our Gas and Power segment was mainly due to the following factors:

- increase in average realization price of natural gas, due to greater participation in the industrial segment sales mix;

- reduction of acquisition/transfer costs of domestic natural gas, reflecting international prices and the appreciation of the *real* against the U.S. dollar;

- increased fixed revenues from energy auctions (regulated market), with the operational start-up of two new thermoelectric plants;

- increased fertilizer margin sales, reflecting growth in demand and higher prices of agricultural commodities;

- use of tax credits.

Biofuel

The decrease of 79% in net income for our Biofuel segment in 2011 compared to 2010 was primarily due to unfavorable sales prices and also to increases in costs for acquisition and transportation of raw-material for biodiesel production and higher operating expenses.

These effects were partially offset by the profitability of the ethanol sector.

Distribution

Net income for our Distribution segment in 2011 decreased 8%, excluding currency effects, compared to 2010 mainly due to increased costs related to commercial services, allowance for doubtful accounts and personnel expenses.

The Distribution segment accounted for 39.2% of the national fuel distribution market in 2011, compared to 38.8% in 2010.

International

The increase of 62% in net income for our International segment was due primarily to the increase in commodities prices in the international market, decreased exploration costs due to write-offs of dry or economically unviable wells, partially offset by the oil tax levied in Nigeria and the higher allowance for marking inventory to market value in Japan, the United States and Argentina.

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Additional Business Segment Information

Set forth below is additional selected financial data by business segment for 2012, 2011 and 2010:

	For the Year Ended December 31,		
	2012	**2011**	**2010**
	(U.S.$ million)		
Exploration and Production			
Sales revenues to third parties(1)(2)	843	516	242
Intersegment net revenues	73,871	73,601	54,031
Total sales revenues(2)	74,714	74,117	54,273
Net income (loss)(3)	23,406	24,326	16,874
Capital expenditures and investments	21,959	20,405	18,621
Property, plant and equipment	102,779	90,633	83,135
Refining, Transportation and Marketing			
Sales revenues to third parties(1)(2)	78,760	80,484	65,397
Intersegment sales revenues	37,950	38,146	32,539
Total sales revenues(2)	116,710	118,630	97,936
Net income (loss)(3)	(11,718)	(5,718)	2,088
Capital expenditures and investments	14,745	16,133	16,198
Property, plant and equipment	63,463	54,629	45,622
Gas and Power			
Sales revenues to third parties(1)(2)	10,515	8,434	7,491
Intersegment sales revenues	1,288	1,304	1,001
Total sales revenues(2)	11,803	9,738	8,492
Net income (loss)(3)	861	1,862	736
Capital expenditures and investments	2,113	2,293	3,964
Property, plant and equipment	21,585	21,968	24,015
Biofuel(4)			
Sales revenues to third parties(1)(2)	90	32	34
Intersegment sales revenues	365	288	238
Total sales revenues(2)	455	320	272
Net income (loss)(3)	(112)	(95)	(53)
Capital expenditures and investments	147	294	664
Property, plant and equipment	255	285	328
Distribution			
Sales revenues to third parties(1)(2)	39,834	43,270	36,564
Intersegment sales revenues	878	731	718
Total sales revenues(2)	40,712	44,001	37,282
Net income (loss)(3)	914	774	710
Capital expenditures and investments	666	679	515
Property, plant and equipment	2,733	2,510	2,404

International			
Sales revenues to third parties(1)(2)	14,061	13,179	10,724
Intersegment sales revenues	3,868	3,777	2,795
Total sales revenues(2)	17,929	16,956	13,519
Net income (loss)(3)	719	1,179	730
Capital expenditures and investments	2,572	2,631	2,712
Property, plant and equipment	10,882	9,871	8,716

(1) As a vertically integrated company, not all of our segments have significant third-party revenues. For example, our Exploration and Production segment accounts for a large part of our economic activity and capital expenditures, but has little third-party revenues.

(2) Revenues from commercialization of oil to third parties are classified in accordance with the points of sale, which could be either the Exploration and Production or Refining, Transportation and Marketing segments.

(3) Excluding non-controlling interests.

(4) As of 2011, the results of our Biofuel segment have been presented separately from our Corporate segment. The 2010 financial information related to our Corporate and Biofuel segments was reclassified accordingly.

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Liquidity and Capital Resources

Overview

Our principal uses of funds are for capital expenditures, dividend payments and repayment of debt. In 2010, 2011 and 2012, we met these requirements with internally generated funds, short-term debt, divestments, long-term debt and cash generated by capital increases. For 2013 and beyond, we believe internally generated funds, divestments and increases in debt, together with a reduction of our cash and cash equivalents position, will continue to allow us to meet our current capital requirements. In 2013, our major cash needs are for our budgeted capital expenditures of U.S.$48.9 billion, the remaining part of announced interest on capital of U.S.$3,067 million and principal payments of U.S.$2,813 million on our long-term debt, leasing and project financing obligations.

Financing Strategy

The objective of our financing strategy is to help us achieve the targets set forth in our 2013-2017 Business and Management Plan released on March 15, 2013, which provides for capital expenditures of U.S.$236.7 billion from 2013 to 2017, U.S.$207.1 billion of which is for projects already under implementation, while U.S.$29.6 billion is for projects that are still under evaluation and subject to final approval by our management.

We will raise debt capital through a variety of medium and long-term financing arrangements, including the issuance of bonds in the international capital markets, supplier financing, project financing and bank financing. We will continue our policy of extending the term of our debt maturity profile.

For 2013, we intend to fund our financial needs through a combination of drawing down our year-end cash balances and existing credit facilities, as well as contracting new debt from a broad range of traditional funding sources, including global debt capital markets, export credit agencies, non-Brazilian government development banks, the BNDES, and Brazilian and international commercial banks. As of April 26, 2013, we have financed part of our needs (in a total amount of U.S.$7,366 million) from various funding sources, including commercial banks, capital markets and the BNDES.

Government Regulation

We are required to submit our annual capital expenditures budget (*Plano de Dispêndio Global*, or PDG) to the Brazilian Ministry of Planning, Budget and Management, and the Ministry of Mines and Energy. Following review by these agencies, the Brazilian Congress must approve the budget. Although the total level of our annual capital expenditures is regulated, the specific application of funds is left to our discretion. Since mid-1991, we have obtained substantial amounts of our financing from the international capital markets, mainly through the issuance of commercial paper and short, medium and long-term notes, and have increasingly been able to raise long-term funds for large capital expenditure items such as rigs and platforms.

The Brazilian Ministry of Planning, Budget and Management controls the total amount of medium and long-term debt that we and our Brazilian subsidiaries can incur through the annual budget approval process. Before issuing medium and long-term debt, we and our Brazilian subsidiaries must also obtain the approval of the National Treasury Secretariat. All of our foreign currency denominated debt, as well as the foreign currency denominated debt of our Brazilian subsidiaries, requires registration with the Central Bank.

However, the issuance of debt by our international subsidiaries is not subject to registration with the Central Bank or approval by the National Treasury Secretariat. In addition, all issuances of medium and long-term notes and debentures require the approval of our board of directors. Borrowings that exceed the approved budgeted amount for any year also require approval of the Brazilian Senate.

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Sources of Funds

Our Cash Flow

On December 31, 2012, we had cash and cash equivalents of U.S.$13,520 million compared to U.S.$19,057 million at December 31, 2011.

Operating activities provided net cash flows of U.S.$27,888 million for 2012 compared to U.S.$33,698 million for 2011 mainly due to lower gross margins driven by the impact of the appreciation of the U.S. dollar on imports of crude oil and oil products and production taxes, as well as higher import volumes in 2012.

Net cash provided by financing activities amounted to U.S.$6,069 million for 2012 compared to U.S.$4,232 million for 2011. This increase was primarily due to the issuance of additional long-term debt, and by lower payment of dividends in 2012, U.S.$3,272 million, compared to U.S.$6,422 million in 2011. We typically pay dividends in the year following the announcement of the corresponding results. In 2012, we paid dividends related to 2011 earnings as well as a large portion of interest on capital related to 2012 earnings in advance of the close of our 2012 fiscal year.

Our net debt increased 32% to U.S.$72,335 million as of December 31, 2012 compared to U.S.$54,922 million as of December 31, 2011, primarily because of the issuance of additional long-term debt necessary to attend higher capital expenditures and lower cash generation from operating activities.

Short-Term Debt

Our outstanding short-term debt serves mainly to support our working capital and our imports of crude oil and oil products, and is provided almost entirely by international banks and includes the current portion of long-term debt and current portion of finance lease obligations. On December 31, 2012, our total short-term debt amounted to U.S.$7,497 million (of which U.S.$2,795 million was the current portion of long-term debt) compared to U.S.$10,111 million on December 31, 2011.

Long-Term Debt

Our outstanding long-term debt consists primarily of securities issued in the international capital markets, debentures issued in the domestic capital markets, amounts outstanding under facilities guaranteed by export credit agencies and multilateral agencies, loans from the BNDES and other financial institutions and project financings, including finance lease obligations. The non-current portion of our total long-term debt amounted to U.S.$88,484 million on December 31, 2012 compared to U.S.$72,718 million on December 31, 2011. This increase was primarily due to international borrowings, mainly in the form of drawings on financing obtained from the issuance of Global Notes, as well as proceeds in the form of Export Credit Notes obtained from the Banco do Brasil and the Caixa Econômica Federal. These financial resources will be used primarily for the development of projects related to oil and gas production, for the construction of ships and pipelines, as well as for the expansion of industrial units. See Note 15 to our consolidated financial statements for the year ended December 31, 2012, for more information.

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Included in these figures at December 31, 2012 are the following international debt issues:

Notes(*)	**Principal Amount (U.S.$ million)**
PifCo's 7.750% Global Notes due 2014	600
PifCo's 2.875% Global Notes due 2015	1,250
PifCo's 2.150% Japanese Yen Bonds due 2016(1)	298
PifCo's 3.875% Global Notes due 2016	2,500
PifCo's 6.125% Global Notes due 2016	899
PifCo's 3.500% Global Notes due 2017	1,750
PESA's 5.875% Notes due 2017	300
PifCo's 4.875% Global Notes due 2018(2)	1,666
PifCo's 5.875% Global Notes due 2018	1,750
PifCo's 8.375% Global Notes due 2018	750
PifCo's 7.875% Global Notes due 2019	2,750
PGF's 3.250% Global Notes due 2019(3)	1,671
PifCo's 5.750% Global Notes due 2020	2,500
PifCo's 5.375% Global Notes due 2021	5,250
PifCo's 5.875% Global Notes due 2022(4)	800
PGF's 4.250% Global Notes due 2023(5)	900
PifCo's 6.250% Global Notes due 2026(6)	1,095
PGF's 5.375% Global Notes due 2029(7)	726
PifCo's 6.875% Global Notes due 2040	1,500
PifCo's 6.750% Global Notes due 2041	2,250

(*) Unless otherwise noted, all debt is issued by PifCo with support from Petrobras through a guaranty.

(1) Issued by PifCo on September 27, 2006 in the amount of ¥ 35 billion, with support from Petrobras through a standby purchase agreement.

(2) Issued by PifCo on December 9, 2011 in the amount of €1.25 billion.

(3) Issued by PGF on October 01, 2012 in the amount of €1.3 billion.

(4) Issued by PifCo on December 9, 2011 in the amount of €600 million.

(5) Issued by PGF on October 01, 2012 in the amount of €700 million.

(6) Issued by PifCo on December 12, 2011 in the amount of £700 million.

(7) Issued by PGF on October 01, 2012 in the amount of £450 million.

Off Balance Sheet Arrangements

As of December 31, 2012, we had no off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Uses of Funds

Capital Expenditures and Investments

We invested a total of U.S.$42,949 million in 2012, a decrease of 0.5% compared to our investments of U.S.$43,164 million in 2011. Our investments in 2012 were primarily directed toward increasing production, modernizing and expanding our refineries and fertilizer plants and the integration and expansion of our pipeline transportation and distribution systems. Of the total capital expenditures in 2012, U.S.$21,959 million was invested in exploration and development projects in Brazil, including investments financed through project financing.

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The following table sets forth our consolidated capital expenditures (including project financings and investments in thermoelectric power plants) for each of our business segments for 2012, 2011 and 2010:

	For the Year Ended December 31		
	2012	**2011**	**2010**
	(U.S.$ million)		
Exploration and Production	21,959	20,405	18,621
Refining, Transportation and Marketing	14,745	16,133	16,198
Gas and Power	2,113	2,293	3,964
Biofuel	147	294	664
Distribution	666	679	515
International			
Exploration and Production	2,347	2,340	2,379
Refining, Transportation and Marketing	131	189	148
Gas and Power	5	31	87
Distribution	72	58	60
Others	17	13	38
Corporate	747	729	839
Total	**42,949**	**43,164**	**43,513**

On March 15, 2013, we announced our 2013-2017 Business and Management Plan, which contemplates total budgeted capital expenditures of U.S.$236.7 billion from 2013 to 2017, U.S.$207.1 billion of which is for projects already under implementation, while U.S.$29.6 billion is for projects that are still under evaluation and subject to final approval by our management.

We expect that U.S.$147.5 billion of our capital expenditures, will be directed towards exploration and production segment in Brazil, totalizing US$ 152.7 billion considering our activities abroad. Our capital expenditure budget for 2013, including our project financings, is U.S.$48.9 billion.

We plan to meet our budgeted capital expenditures primarily through internally generated cash, issuances in the international capital markets, project finance loans, commercial bank loans and other sources of capital. Our actual capital expenditures may vary substantially from the projected numbers set forth above as a result of market conditions and the cost and availability of the necessary funds.

Dividends

Our board of directors approved on February 04, 2013 a total dividend distribution of R$8,876 million (U.S.$4,499 million) for 2012 earnings, which includes interest on capital already approved by our board of directors. Our shareholders will hold an Annual General Meeting on April 29, 2013 to deliberate about such total dividend distribution. We paid U.S.$1,432 million of this amount to shareholders in the form of interest on capital on May 31, 2012, in advance of the close of our 2012 fiscal year. Upon deliberation of our Annual General Meeting, the remaining U.S.$3,067 million in dividends and interest on capital relating to our 2012 earnings is expected to be paid until the end of the fiscal year 2013, restated according to the SELIC rate from December 31, 2012 to the date of payment. The total amount of 2012 dividends approved by our board of directors is equivalent to R$0.47 (U.S.$0.24) per common share, R$0.96 (U.S.$0.48) per preferred share, R$0.94 (U.S.$0.48) per common ADS and R$1.92 (U.S.$0.96) per preferred ADS. For more information on our dividend policy, including a description of the minimum preferred dividend to which our preferred shareholders are entitled under our bylaws, see “Mandatory Distribution” and “Payment of Dividends and interest on Capital” in Item 10. “Additional Information—Memorandum and Articles of Incorporation.

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Contractual Obligations

The following table summarizes our outstanding contractual obligations and commitments at December 31, 2012:

		Payments Due by Period			
	Total	**< 1 year**	**1-3 years**	**3-5 years**	**> 5 years**
			(U.S.$ million)		
Contractual obligations					
Balance sheet items:(1)					
Long-term debt obligations (includes accrued interest)	91,279	2,795	11,301	23,054	54,129
Capital (finance) lease obligations	104	8	17	15	64
Total balance sheet items	91,383	2,803	11,318	23,069	54,193
Other long-term contractual commitments					
Natural gas ship-or-pay	4,637	667	1,304	1,327	1,339
Service contracts	62,651	27,291	20,396	7,057	7,907
Natural gas supply agreements(2)	17,895	2,844	5,277	5,193	4,581
Operating leases	81,586	16,724	23,106	12,207	29,549
Purchase commitments	20,141	6,161	7,115	4,942	1,923
International purchase commitments	20,784	8,784	6,143	2,945	2,912
Total other long-term commitments	207,694	62,471	63,341	33,671	48,211
Total	**299,077**	**65,274**	**74,659**	**56,740**	**102,404**

(1) Excludes the amount of U.S.$39,499 million related to our pension fund obligations that are guaranteed by U.S.$27,684 million in plan assets and the amount of US$ 9,441 million related to our provision for decommissioning costs. Information on employees' postretirement benefit plans and on the provision for decommissioning costs are set forth in Notes 20.5 and 18, respectively, of our consolidated financial statements for the year ended December 31, 2012.

(2) Amounts disclosed assume that the counterparty would not fulfill certain precedent conditions in the agreement. For additional information about natural gas supply agreements entered into by us, please refer to Item 4. “Information on the Company–Gas and Power–Natural Gas–Long-Term Natural Gas Commitments”.

Critical Accounting Policies and Estimates

The following summary provides information about those areas that require the most judgment or involve a higher degree of complexity in the application of the accounting policies that currently affect our financial condition and results of operations. The accounting estimates we make in these contexts require us to make assumptions about matters that are highly uncertain.

This summary addresses only those estimates that we consider most important based on the degree of uncertainty and the likelihood of a material impact if we used a different estimate. There are many other areas in which we use estimates about uncertain matters, but the reasonably likely effect of changed or different estimates is not material to our financial presentation.

For more detailed information about our Critical Accounting Policies and Estimates, please refer to Notes 2 and 4 to our audited consolidated financial statements as of December 31, 2012.

Oil and Gas Reserves

Oil and gas reserve quantities are estimated based on engineering and geological information (such as well logs, pressure data and fluid sample core data), as well as on economical information, and are used as the basis for calculating unit-of-production depreciation rates and for impairment assessment. These estimates require the application of judgment and are subject to ongoing revisions, either upward or downward, based on new information that becomes available. New information include (1) re-evaluation of already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in prices and costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment/facility capacity.

Oil and gas reserves include both proved and unproved reserves. According to the definitions prescribed by the SEC in Regulation S-X, proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made).

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Proved reserves can be further subdivided into developed and undeveloped reserves. Developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. At December 31, 2012, proved developed reserves represented 60.7 percent of the total proved reserves of Petrobras (including consolidated and equity company reserves).

Although the Company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

For more detailed information about Oil and Gas Reserves, please refer to "Supplementary Information on Oil and Gas Exploration and Production" in our audited consolidated financial statements as of December 31, 2012.

Impact of Oil and Gas Reserves on Depreciation and Depletion

Depreciation, depletion and amortization of proved oil and gas producing properties is accounted for according to the unit-of-production method based on the ratio of reserves produced applied to the depreciable amount of the asset. The depreciable amount is the cost of the asset, less its residual value, if material. Revisions of the Company's proved developed and undeveloped reserves impacts prospectively the amounts: of depreciation and depletion charged in the results of operations and the carrying amounts of oil and gas properties assets.

For more detailed information about Depreciation and Depletion, please refer to Notes 4 and 11 to our audited consolidated financial statements as of December 31, 2012.

Impact of Oil and Gas Reserves and Prices on Testing for Impairment

Oil and gas producing properties are tested for impairment whenever there is any indication that the carrying amounts may not be recoverable. We estimate the future and discounted cash flows of the affected properties to judge the recoverability of carrying amounts. In general, analyses are based on proved reserves and probable reserves, in accordance with the reserve definitions prescribed by the SPE; the percentage of probable reserves that we include in cash flows does not exceed our past success ratios in developing probable reserves.

We perform asset valuation analyses on an ongoing basis as a part of our management program by reviewing whether the carrying amounts of any of our assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices.

In general, we do not view temporarily low oil prices as a trigger event for conducting impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop precipitously, industry prices over the long term will continue to be driven by market supply and demand fundamentals. Accordingly, any impairment tests that we perform make use of our long-term price assumptions for the crude oil and natural gas markets. These are the same price assumptions that are used in our planning and budgeting processes and our capital investment decisions, and they are considered to be reasonable, conservative estimates given market indicators and past experience. Significantly lower future oil and gas prices could lead to impairments in the future, if such decreases were considered to be indicative of long-term trends. In addition, significant changes in production curve expectation, discount and/or required production and lifting costs, could affect impairment analysis.

For more detailed information about Impairment, please refer to Notes 4 and 11 to our audited consolidated financial statements as of December 31, 2012.

Impairment (other than oil and gas producing properties)

The impairment test comprises a comparison of the carrying amount of an individual asset or a cash-generating unit with its recoverable amount. The recoverable amount of an asset or a cash-generating unit is the higher of its fair value less costs of disposal and its value in use. Value in use is estimated based on the present value of the risk-adjusted future cash flows expected to arise from the continuing use of an asset or cash-generating unit.

Value in use is generally used for impairment testing purposes, including for impairment test of investments in associates - of which the most significant are in petrochemical companies. For these investments, the expected future cash flow is estimated based on the specificity of the business cycle (including the effects of projects under development) and is adjusted for country, currency and price risks. The discount rate is derived from the weighted average cost of capital risk-adjusted to reflect the way that the market would assess the specific risks associated with the asset's estimated cash flows, excluding risks for which the estimated cash flows were already adjusted.

The assessment of the value in use of an asset involves the use of estimates on uncertain assumptions, such as future production curves, future commodity prices, sales revenues growth, operating margins, discount rates, foreign exchange rates, inflation rates and investments required for carrying out projects.

We have an investment in Braskem S.A. that is accounted for under the equity method. Braskem's shares are publicly traded on exchanges in São Paulo, Madrid and New York. The carrying value of this investment at December 31, 2012 was U.S.$2,703 million, including goodwill. The quoted market value at December 31, 2012, was U.S.$1,473 million, based on the quoted values of both our shares in common stock – we own 47% of the outstanding shares, and preferred stock – we own 22% of the outstanding shares. Only approximately 3% of the common shares are held by non-affiliates and there is extremely limited trading. The primary difference between the common shares and the preferred shares is that the common shares can vote and the preferred shares have a dividend preference. If the common shares were valued at the same share price as the preferred, the quoted market value would have been U.S.$1,805 million.

Given the operational relationship between Petrobras and Braskem, we did not look to the quoted market price to determine if there was an impairment. Rather, we determined the value in use by looking at our share of the present value of the estimated future cash flows expected to be generated by Braskem. Using this method we concluded that the value in use is higher than the carrying value.

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The key assumptions on which we based our cash flow projections to determine the value in use of Braskem, were derived from Braskem´s assessments and Petrobras' business plan, as approved by each Board of Directors, and are as follows:

- estimated average exchange rate of R$2.00 to U.S.$1.00 in 2013, with the *real* strengthening against the U.S. dollar to R$1.85 in the long term;
- Brent crude oil price of U.S.$107.00 for 2013, declining to U.S.$100.00 in the long term;
- prices of feedstock and petrochemicals reflecting international trends (projected);
- growth of petrochemical products sales volumes estimated based on projected Brazilian and global G.D.P growth;
- increases in the EBITDA margin following the next cyclical increase of the petrochemical industry during the next several years and declining down thereafter; and
- a 16.5% pre-tax discount rate derived from the post-tax cost of the shareholder, according to the Capital Asset Price Model.

In addition, we performed a sensitivity analysis and determined that even if the actual future margins were to be 20% below the margins we projected, our investment in Braskem would still be fully recovered.

For more detailed information about our impairment policies, please refer to Notes 4.8 and 10 to our audited consolidated financial statements as of December 31, 2012.

Pension and Other Post-Retirement Benefits

The determination of the expense and liability relating to our pension and other post-retirement benefits involves the use of judgment in the determination of actuarial assumptions. These include estimates of future mortality, withdrawal, changes in compensation and discount rate to reflect the time value of money, the rate of return on plan assets, as well as actuarial assumptions regarding the variables that will determine the ultimate cost of providing post-retirement benefits such as biological and economic assumptions, medical costs estimates, as well as historical data related to expenses incurred and employee contributions. These assumptions are reviewed at least annually and may differ materially from actual results due to changing market and economic conditions, regulatory events, legal issues, higher or lower withdrawal rates or longer or shorter life spans of participants.

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For more detailed information about Pension and Other Post Retirement Benefits, please refer to Note 20 to our audited consolidated financial statements as of December 31, 2012.

Litigation, Tax Assessments and Other Contingencies

We are a defendant in numerous legal proceedings involving civil, tax, labor, corporate and environmental issues arising from the normal course of our business. We are also sometimes held liable for spills and releases of oil products and chemicals from our operating assets. Based on advice from our legal advisors and our management's best estimates, we have classified the potential outflow of future economic benefit.

Provisions are recognized when there is a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

For more detailed information about Litigation, Tax Assessments and Other Contingencies, please refer to Note 27 to our audited consolidated financial statements as of December 31, 2012.

Dismantling of Areas and Environmental Remediation

Under various contracts, permits and regulations, we have material legal obligations to remove equipment and restore the land or seabed at the end of operations at production sites. Our most significant asset removal obligations involve removal and disposal of offshore oil and gas production facilities worldwide. We accrue the estimated discounted decommissioning costs (for dismantling and removing these facilities) at the time of installation of the assets. We also estimate costs for future environmental clean-up and remediation activities based on current information on costs and expected plans for remediation. Estimating asset retirement, removal and environmental remediation costs requires performing complex calculations that necessarily involve significant judgment because our obligations are many years in the future, the contracts and regulation have vague descriptions of what removal and remediation practices and criteria will have to be met when the removal and remediation events actually occur and asset removal technologies and costs are constantly changing, along with political, environmental, safety and public relations considerations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty.

In 2012, we reviewed and revised our estimated costs associated with well abandonment and the demobilization of oil and gas production areas. As a result, our provision for decommissioning costs increased by U.S.$5 billion, mainly due to the impact of:

a) Devaluation of 9% of the Brazilian *real* in relation to the U.S dollar (from R$1.8758 at December 31, 2011 to R$2.0435 at December 31, 2012) – a U.S.$400 million increase;

b) Decrease of 25.2% in the risk free credit adjusted rate (from 3.09% at December 31, 2011 to 2.31% at December 31, 2012) – a U.S.$2,100 million increase; and

c) Increase in actual abandonment costs resulting from technical and economic factors to reflect mainly longer operation periods based on recent experience in the abandonment of wells and facilities decommissioning. These costs were partially offset by the positive effect of expected longer abandonment dates due to technical revisions and more favorable economic conditions – a U.S.$2,400 million increase.

The company is constantly conducting studies to incorporate technologies and procedures seeking to optimize the operations of abandonment, considering the industry best practices.

For more information about the annual changes in the decommissioning provisions, please refer to Note 18 to our audited consolidated financial statements as of December 31, 2012.

Derivative Instruments

Accounting for derivative transactions requires us to employ judgment to compute fair market values, which are used as the basis for recognition of the derivative instruments in our consolidated financial statements. Such measurement may depend on the use of estimates such as estimated future prices, long-term interest rates and inflation indices, and becomes increasingly complex when the instrument being valued does not have counterparts with similar characteristics traded in an active market.

For more detailed information about Derivative Instruments please refer to Note 30 to our audited consolidated financial statements as of December 31, 2012.

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Research and Development

We are deeply committed to research and development as a means to extend our reach to new production frontiers and achieve continuous improvement in operations. We have a history of successfully developing and implementing innovative technologies, including the means to drill, complete and produce wells in increasingly deep water. We are one of the largest investors in research and development among the world's major oil companies, and we spend a large percentage of revenues in research and development. Our Brazilian oil and gas concession agreements require us to spend at least 1% of our gross revenues originating from high productivity oil fields on research and development, of which up to half is invested in our research facilities in Brazil and the remainder is invested in research and development in Brazilian universities and institutions registered with the ANP for this purpose.

In 2012, we spent U.S.$1,143 million on research and development, equivalent to 0.8% of our sales revenues. In 2011, we spent U.S.$1,454 million on research and development, equivalent to 1.0% of our sales revenues. In 2010, we spent U.S.$989 million on research and development, equivalent to 0.8% of our sales revenues.

Our research and development activities focus on three main goals:

(1) Expansion of our current businesses through the:

(a) discovery of new exploratory frontiers through comprehensive, basin-scale geological and geophysical investigations of Brazilian frontier areas, both onshore and offshore, and implementation of innovative seismic processing and inversion algorithms;

(b) enhancement of oil and gas final recovery by the use of innovative sea water, CO_2 and polymer injection systems;

(c) enhancement of the pre-salt production systems and its reservoirs' final recovery by intensive usage of compact subsea solutions, injection systems and the capacity enhancement of the new pre-salt FPSO units;

(d) development of new or enhanced subsea production systems and equipment for deep and ultra-deep waters based on compact subsea oil/water/gas separation, sea floor produced water re-injection, improved gas-lift technology, sea floor oil boosting and gas compression and a new generation of electrical submersible pumps;

(e)

optimization and development of drilling and production solutions for unconventional reservoirs, shale gas, gas hydrates, coal bed methane, tight gas and shale oil, by geophysical investigations of the Brazilian onshore frontier areas and well design optimization through cost effective and currently available technologies;

(f) optimization of our natural gas logistics and final usage, through the development of solutions for offshore and stranded gas, such as chemical conversion, compression and subsea to shore, and the optimization of our onshore assets;

(g) application of available up-to-date logistic technologies to improve our integrated offshore operations;

(h) optimization of the Brazilian oil and derivatives supply and the exportation of oil and its derivatives;

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(i) development of technologies and mixing devices to optimize the refining processes for pre-salt oils, such as desalter operation, and;

(j) development of technologies to enhance the flexibility of middle distillates or gasoline, in order to meet market demands;

(2) Providing a mix of products compatible with the energy demands of the future through the:

(a) development of new fuels, lubricants and special product formulations such as podium diesel and podium gasoline;

(b) development of new technologies for petrochemical activities such as catalyst systems for polypropylene and ethylene production from olefins and polystyrene and polyester (raw materials and polymers) from both fossil and renewable sources;

(c) optimization of our ammonia and urea production plants through advanced real time process control optimization and development of new technologies for urea based fertilizers and ruminant feedstock, through mixed fertilizer formulations with micronutrients;

(e) development of competitive second generation biofuel production processes, which use residual biomass as feedstock, through biochemical and thermochemical routes such as pyrolysis and gasification, and;

(f) optimization of our thermoelectric power plants, with emphasis on operation and maintenance cost reduction, and research and development on renewable energy technologies, such as concentrated solar, photovoltaic and wind power;

(3) Ensuring that our activities are environmentally sustainable. We aim throughout our entire business to:

(a) reduce water consumption and the volume and toxicity of wastewater discharges, by the selection and development of new chemical products and formulations and by water re-use increase through an extensive portfolio of primary, secondary and tertiary treatment routes;

(b) reduce our emissions of air pollutants, CO_2 and other greenhouse gases based on intensive re-injection of CO_2 into our production reservoirs, selection and development of technologies for pollutants abatement and carbon capture storage and sequestration;

(c) increase the energy efficiency of our processes and products through research and development in combustion, heat transfer processes and advanced thermal cycles;

(d) prevent and mitigate the environmental impact of our activities through extensive offshore research in deepwater biodiversity characterization and the development of innovative operation standards, and;

(e) ensure the integrity, safety and reliability of all our industrial facilities, by the development and implementation of new materials and process equipment, online process and equipment integrity monitoring and diagnosis, inspection techniques, new process tuning systems, advanced control tools, real-time optimization and simulators for design and process analysis.

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In the three-year period ended December 31, 2012, our research and development operations were awarded 75 patents in Brazil and 152 overseas. Our portfolio of patents covers all of our areas of activities.

We have operated a dedicated research and development facility in Rio de Janeiro, Brazil since 1966. As a result of its expansion in 2010, this is one of the largest facilities of its kind in the energy sector and the largest in the southern hemisphere, with laboratories especially dedicated to pre-salt technologies. As of December 31, 2012, this facility has 1,897 employees, 1,420 of which are exclusively dedicated to research, development and basic engineering.

We also have several semi-industrial scale prototype plants throughout Brazil that are in proximity to our industrial facilities and that are aimed at scaling up new industrial technologies at reduced costs. In 2012, we conducted research and development through joint research projects with more than 100 universities and research centers in Brazil and abroad and participated in technology exchange and assistance partnerships with several oilfield service companies, small technology companies and other operators.

Trends

We plan to continue expanding all segments of operations in our target markets in accordance with our 2013-2017 Business and Management Plan. In support of this goal we plan total capital expenditures of U.S.$236.7 billion over 2013-2017, U.S.$207.1 billion of which is for projects already under implementation, while U.S.$29.6 billion is for projects that are still under evaluation and subject to final approval by our management. Of this total, approximately 65.0% is in the exploration and production segment (Brazil and abroad), where constant investment in exploration and development is needed to exploit newly discovered resources and offset natural declines in production from existing fields as they mature.

We expect that the demand for oil products in Brazil will continue to increase rapidly driven primarily by economic growth and the increase in purchasing power of the middle class. In 2012, we met this incremental growth in demand by increasing imports as our refining capacity was not sufficient to meet the increased demand. This increase in imports increased our cost of sales and decreased our margins in 2012. We expect this trend to continue in the near future as we anticipate that Brazilian demand will grow at a faster pace than our refining capacity.

The price we realize for the oil we produce is determined by international oil prices, although we generally sell our oil at a discount to Brent and other light oil benchmark prices because it is heavier and thus more expensive to refine. In 2012, oil price trends were affected by political unrest in the Middle East as well as by fluctuations in macroeconomic conditions, primarily in Europe. The Brent benchmark price experienced greater variation in 2012 as compared to 2011, with a minimum price of U.S.$88.74/bbl, a maximum price of

U.S.$126.65/bbl and an average price of U.S.$111.58/bbl, the highest nominal Brent average price recorded to date. The economic outlook and continuing political turmoil in the Middle East and in North Africa will remain the key determinants of oil price trends in the short term. A fast-paced recovery coupled with slow supply-side response can result in higher prices in the medium term. On the other hand, if economic recovery expectations are not met, especially those regarding non-OECD (organization for economic co-operation and development) economies and there is an increase of the oil production in the U.S. (more supply of unconventional oil), oil prices may drop below current levels. In addition, recent geopolitical concerns may persist, potentially driving prices higher in the short term.

For the 2013 to 2017 period, we plan to continue to focus on increasing our refining throughput and our capacity to refine heavier crudes. The refining expansion program currently underway may improve our refining margins, since the new refineries will be able to process a heavier crude slate with lower costs while having a higher yield of middle distillate products (primarily of diesel and jet fuel) with higher potential demand and growth margins.

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Each year, we review and revise our long-term Business and Management Plan in order to adapt to changing market conditions and to revise our investment levels in accordance with updated scenarios and projected cash flows. The guidance provided by our board of directors is instrumental in this review process. For the 2013-2017 period, we have retained the targets for our net-debt-to-equity ratio in the range of 25% to 35% and for our net-debt-to-EBITDA ratio is not to exceed 2.5:1 in 2014 and to reach 1.65:1 by 2017.

Item 6. Directors, Senior Management and Employees

Directors and Senior Management

Directors

Our board of directors is composed of a minimum of five and up to ten members and is responsible for, among other things, establishing our general business policies. The members of the board of directors are elected at the annual general meeting of shareholders, including the employee representative previously selected by means of a separate voting procedure.

Under Brazilian Corporate Law, shareholders representing at least 10% of the company's voting capital have the right to demand that a cumulative voting procedure be adopted to entitle each common share to as many votes as there are board members and to give each common share the right to vote cumulatively for only one candidate or to distribute its votes among several candidates. Pursuant to regulations promulgated by the CVM, the 10% threshold requirement for the exercise of cumulative voting procedures may be reduced depending on the amount of capital stock of the company. For a company like Petrobras, the threshold is 5%. Thus, shareholders representing 5% of our voting capital may demand the adoption of a cumulative voting procedure.

Specifically, pursuant to Law No. 12,353 and Act No. 026, an employee representative chosen by our active employees must be a member of our board of directors.

Furthermore, our bylaws enable (i) minority preferred shareholders that together hold at least 10% of the total capital stock (excluding the controlling shareholders) to elect and remove one member to our board of directors; (ii) minority common shareholders to elect one member to our board of directors, if a greater number of directors is not elected by such minority shareholders by means of the cumulative voting procedure; and (iii) our employees to elect one member to our board of directors by means of a separate voting procedure. Our bylaws provide that, regardless of the rights above granted to minority shareholders, the Brazilian federal government always has the right to elect the majority of our directors, independently of their number. In addition, under Law 10,683, dated May 28, 2003, one of the board members elected by the Brazilian federal government must be indicated by the Minister of Planning, Budget and Management. The maximum term for a director is one year, but re-election is permitted. In accordance with the Brazilian Corporate Law, the shareholders may remove any director from office at any time with or without cause at an extraordinary meeting of shareholders. Following an election of board members under the cumulative vote procedure, the removal of any board member by an extraordinary meeting of shareholders will result in the removal of all the other members, after which new elections must be held.

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We currently have ten directors. The following table sets forth certain information with respect to these directors:

Name	Date of Birth	Position	Current Term Expires	Business Address
Guido Mantega(1)	April 7, 1949	Chair	March 2013	Esplanada dos Ministérios – Bloco P 5º andar Brasília – DF Cep 70.048-900
Maria das Graças Silva Foster(1)	August 26, 1953	Director	March 2013	Avenida República do Chile, no. 65 23º andar Rio de Janeiro – RJ Cep 20.031-912
Miriam Aparecida Belchior(1)	February 5, 1958	Director	March 2013	Esplanada dos Ministérios – Bloco K 7º andar Brasília – DF Cep 70.040-906
Francisco Roberto de Albuquerque(1)	May 17, 1937	Director	March 2013	Alameda Carolina, no. 594 Itú – SP Cep 13.306-410
Josué Christiano Gomes da Silva(2)	December 25, 1963	Director	March 2013	Avenida Paulista, no. 1.754 2ª Sobreloja São Paulo – SP

				Cep 01.310-920
Jorge Gerdau Johannpeter(3)	December 8, 1936	Director	March 2013	Av. Farrapos, no. 1.811 Porto Alegre – RS Cep 90.220-005
Márcio Pereira Zimmermann(1)	July 1, 1956	Director	March 2013	Esplanada dos Ministérios – Bloco U Sala 705 Brasília – DF Cep 70.065-900
Luciano Galvão Coutinho(1)	September 29, 1946	Director	March 2013	Av. República do Chile, no. 100 22º andar Rio de Janeiro – RJ Cep 20.031-917
Sergio Franklin Quintella(1)	February 21, 1935	Director	March 2013	Praia de Botafogo, no. 190 12º andar Rio de Janeiro – RJ Cep 22.250-900
Sílvio Sinedino Pinheiro(4)	June 25, 1951	Director	March 2013	Avenida República do Chile, no. 330 12º andar Rio de Janeiro – RJ Cep 20.031-170

(1) Appointed by the controlling shareholder.

(2) Appointed by the minority common shareholders.

(3) Appointed by the minority preferred shareholders.

(4) Appointed by our employees.

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Guido Mantega—Mr. Mantega has been our Chairman of the board of directors since March 19, 2010, after being a member of this board since April 3, 2006. He is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. Mr. Mantega was a member of the Remuneration and Succession Committee of our board of directors from October 15, 2007 to April 30, 2010. Mr. Mantega has been Brazil's Minister of Finance since March 28, 2006, and he served as chairperson of the Group of 20 Finance Ministers and Central Bank Governors (G-20) in 2008. He is a member of the Conselho de Desenvolvimento Econômico e Social—CDES (Economic and Social Development Council), an advisory body to the Brazilian federal government. Mr. Mantega has also held the posts of Brazil's Minister of Planning, Budget and Management and of president of the Banco Nacional de Desenvolvimento Econômico e Social—BNDES (Brazilian Development Bank). He received a bachelor's degree in economics from the Escola de Economia, Administração e Contabilidade—FEA (School of Economy, Administration and Accounting) at the Universidade de São Paulo—USP (University of São Paulo) in 1971, and a Ph.D. in development sociology from the Faculdade de Filosofia, Letras e Ciências Humanas—FFLCH (School of Philosophy, Literature and Human Sciences) at USP, and completed specialized studies at the Institute of Development Studies—IDS at the University of Sussex, England in 1977.

Maria das Graças Silva Foster—Ms. Foster has been our Chief Executive Officer since February 13, 2012 and our Chief International Officer since July 23, 2012. She is also a member of our board of directors, the board of directors of Petrobras Distribuidora S.A. – BR and the board of directors of Petrobras Biocombustível S.A. – PBIO. Ms. Foster is also chairperson of the boards of directors of Petrobras Transporte S.A. – TRANSPETRO, Petrobras Gás S.A. – GASPETRO and Instituto Brasileiro de Petróleo Gás e Biocombustíveis – IBP. From September 2007 to February 2012, she served as Petrobras Chief Gas & Power Officer. From May 2006 to September 2007, Ms. Foster was the CEO of Petrobras Distribuidora S.A. During that period, Ms. Foster was also the chairperson of the Board of Liquigás Distribuidora S.A. and Vice-President of the Board of Companhia Brasileira de Petróleo Ipiranga. Previously, she acted as the CEO and Chief Investor Relations Officer of Petrobras Química S.A. – Petroquisa, a position she took over in September 2005. In that period, she was also the Executive Manager for Petrochemicals and Fertilizers for Petrobras. She holds a degree in chemical engineering from the Universidade Federal Fluminense – UFF (Fluminense Federal University), a master's degree in nuclear and chemical engineering and a post-graduate degree in nuclear engineering from the Universidade Federal do Rio de Janeiro – UFRJ (Federal University of Rio de Janeiro) and an MBA in economics from the Fundação Getulio Vargas – FGV (Getulio Vargas Foundation).

Miriam Aparecida Belchior—Ms. Belchior has been a member of our board of directors since July 22, 2011, and is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. She was appointed as a member of the Environment Committee of our board of directors on December 22, 2011. Since January 1, 2011, she has been State Minister of Planning, Budget and Management. From 2002 to 2010, she was the Articulation and Monitoring Sub-head of the Deputy Chief of Staff, responsible for connecting government actions and monitoring strategic projects. In 2007, she served as Executive Secretary for the Programa de Aceleração do Crescimento—PAC (Growth Acceleration Program) and became its General Coordinator in April 2010. Ms. Belchior is an engineer and holds a master's degree in public administration and government from the Fundação Getulio Vargas-SP (Getulio Vargas Foundation). She served as a professor with the Fundação para Pesquisa e Desenvolvimento da Administração, Contabilidade e Economia—FUNDACE (Foundation for Research and Development of Administration, Accounting and Economics) and the Universidade de São Marcos (University of São Marcos).

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Francisco Roberto de Albuquerque—Mr. de Albuquerque has been a member of our board of directors since April 2, 2007, and he is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. He has been a member of the Audit Committee and the Remuneration and Succession Committee of our board of directors since April 13, 2007, and October 15, 2007, respectively. He earned a bachelor's degree in military sciences from the Academia Militar das Agulhas Negras—AMAN (Agulhas Negras Military Academy) in Resende, in the State of Rio de Janeiro, in 1958 and in economics from the Faculdade de Ciências Econômicas de São Paulo (São Paulo College of Economic Sciences) at Fundação Álvares Penteado (Álvares Penteado Foundation) in 1968, a master's degree in military sciences from the Escola de Aperfeiçoamento de Oficiais—EsAO (Advanced Military School) in 1969, and a Ph.D. in military sciences from the Escola de Comando e Estado-Maior do Exército—ECEME (Military Officer Training School) in Rio de Janeiro in 1977.

Josué Christiano Gomes da Silva—Mr. Josué Gomes has been a member of our board of directors since October 28, 2011, a member of its Audit Committee since November 11, 2011, and a member of the board of directors of Petrobras Distribuidora S.A.—BR. Currently, he is the Chairman and Chief Executive Officer of Companhia de Tecidos Norte de Minas—Coteminas, Latin America's largest textile group. He is also the founder and Chairman of the Board of Cantagalo General Grains S.A., President of the International Textile Manufacturers' Federation—ITMF, Co-Chair of the Brazil – United States CEOs Forum, a board member of Embraer and the Instituto de Estudos para o Desenvolvimento Industrial—IEDI (Institute of Industrial Development Studies). He received a bachelor's degree in civil engineering from the Universidade Federal de Minas Gerais (Federal University of Minas Gerais), a law degree from Faculdades Milton Campos (Milton Campos Faculties) and a master's degree in business administration from Vanderbilt University, where he received the Founder's Medal in recognition of his academic achievement.

Jorge Gerdau Johannpeter—Mr. Johannpeter has been a member of our board of directors since October 19, 2001, and is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. He was appointed a member of the Remuneration and Succession Committee of our board of directors on October 15, 2007 and a member of the Environment Committee on December 22, 2011. Mr. Johannpeter is the Chairman of the board of directors of Gerdau, a member of the board of directors of the Instituto Aço Brasil—IABr (Brazilian Steel Institute) and the World Steel Association, and a member of the Conselho de Desenvolvimento Econômico e Social—CDES (Economic and Social Development Council). He is also the Chairman of the Câmara de Políticas de Gestão, Desempenho e Competitividade (Chamber of Management, Performance and Competitiveness Policies) of the Brazilian federal government. Mr. Johannpeter is involved in Brazil's non-profit sector as president of the board of the Programa Gaúcho da Qualidade e Produtividade—PGQP (State Program for Quality and Productivity in Rio Grande do Sul), leader of the Movimento Brazil Competitivo—MBC (Movement for Brazilian Competitiveness), member of the Associação Brasileira da Qualidade—ABQ (Brazilian Quality Association) and the deliberative council of Parceiros Voluntários (Volunteer Partners). He received a bachelor's degree in law and social sciences from the Universidade Federal do Rio Grande do Sul—UFRGS (Federal University of Rio Grande do Sul), Porto Alegre, in 1961.

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Márcio Pereira Zimmermann—Mr. Zimmermann has been a member of our board of directors since March 22, 2010 and is also a member of the board of directors of Petrobras Distribuidora S.A. – BR. He has been the President of the Remuneration and Succession Committee of our board of directors since April 29, 2010. Mr. Zimmermann is currently the Executive Secretary (Deputy Minister) of the Ministry of Mines and Energy—MME, where he previously served as Minister, Executive Secretary and Secretary for Energy Planning and Development. Mr. Zimmermann is also the Chairman of the board of directors of Centrais Elétricas Brasileiras—Eletrobras, where he previously served as the Engineering Executive Officer, and the Chairman of the board of directors of Furnas Centrais Elétricas S.A. He has been a member of the Conselho Nacional de Política Energética—CNPE (National Energy Policy Council) since February 2009. He was also the Chairman of the board of directors of Furnas Centrais Elétricas S.A., the Energy Production and Commercialization Executive Officer and Technical Executive Officer of Eletrosul Centrais Elétricas S.A., and the Research and Development Executive Officer of Centro de Pesquisas de Energia Elétrica—CEPEL (Electrical Energy Research Center). Mr. Zimmermann holds a bachelor’s degree in electric engineering from the Pontifícia Universidade Católica do Rio Grande do Sul – PUC-RS (Pontifical Catholic University of Rio Grande do Sul), a post-graduate degree in power systems engineering from the Universidade Federal de Itajubá – UNIFEI (Federal University of Itajubá), and a master’s degree in electrical engineering from the Pontifícia Universidade Católica do Rio de Janeiro – PUC-Rio (Pontifical Catholic University of Rio de Janeiro).

Luciano Galvão Coutinho—Mr. Coutinho has been a member of our board of directors since April 4, 2008, and is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. He has been the President of the Banco Nacional de Desenvolvimento Econômico e Social—BNDES (Brazilian Development Bank) since April 27, 2007. In addition, Mr. Coutinho is a member of the board of directors of Vale S.A., a member of the Curator Committee for the Fundação Nacional da Qualidade—FNQ (Brazilian Quality Foundation), and the BNDES representative at the Fundo Nacional de Desenvolvimento Científico e Tecnológico—FNDCT (Brazilian Fund for Scientific and Technological Development). Mr. Coutinho has a Ph.D. in economics from Cornell University, a master’s degree in economics from the Fundação Instituto de Pesquisas Econômicas—Fipe (Institute of Economic Research) at the Universidade de São Paulo—USP (University of São Paulo), and a bachelor’s degree in economics from USP.

Sergio Franklin Quintella—Mr. Quintella has been a member of our board of directors since April 8, 2009, and is also a member of the board of directors of Petrobras Distribuidora S.A.—BR. He has been a member of the Audit Committee of our board of directors since November 13, 2009 and was appointed its president on November 11, 2011. He is vice president of Fundação Getulio Vargas—FGV. He was member of the board of directors of the Banco Nacional de Desenvolvimento Econômico e Social—BNDES (Brazilian Development Bank) from 1975 to 1980, member of Conselho Monetário Nacional (National Monetary Council) from 1985 to 1990, and president of the Tribunal de Contas (Court of Auditors) of the State of Rio de Janeiro from 1993 to 2005. Mr. Quintella holds a bachelor’s degree in civil engineering from the Pontifícia Universidade Católica do Rio de Janeiro—PUC-Rio (Pontifical

Catholic University of Rio de Janeiro), a bachelor's degree in economics from the Faculdade de Economia do Rio de Janeiro (College of Economics of Rio de Janeiro) and a post-graduate degree in economic engineering from the Escola Nacional de Engenharia (National Engineering School). He also holds a master's degree in business from IPSOA Institute, in Turin, Italy and graduated from the Advanced Management Program at Harvard Business School. Mr. Quintella is currently a member of the council of PUC-Rio.

Sílvio Sinedino Pinheiro—Mr. Sinedino has been a member of our board of directors since March 20, 2012, and is the representative of our employees. He is currently the chair of the Audit Committee of Petros, to which he was elected in 2009. He is also the current president of AEPET - Associação dos Engenheiros da Petrobras (Petrobras Association of Engineers). From 2002 to 2005, he was a director of Sindicato dos Petroleiros do Estado do Rio de Janeiro—Sindipetro-RJ (Oil Workers' Union of the State of Rio de Janeiro). He is a systems analyst at Petrobras and develops seismic processing software for our E&P segment. Mr. Sinedino holds a bachelor's degree in electrical engineering from the Pontifícia Universidade Católica do Rio de Janeiro–PUC-Rio (Pontifical Catholic University of Rio de Janeiro) as well as master's degrees in computer science and in business administration, both from the Instituto Alberto Luiz Coimbra de Pós-Graduação e Pesquisa em Engenharia–COPPE/UFRJ (the Alberto Luiz Coimbra Institute of Post-Graduate Studies and Research in Engineering of the Federal University of Rio de Janeiro).

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Executive Officers

Our board of executive officers, composed of the Chief Executive Officer (CEO) and seven executive officers, is responsible for our day-to-day management. Our executive officers are Brazilian nationals and reside in Brazil. Under our bylaws, the board of directors elects the executive officers, including the CEO, and must consider personal qualification, knowledge and specialization in electing executive officers to their respective areas. The maximum term for our executive officers is three years, but re-election is permitted. The board of directors may remove any executive officer from office at any time with or without cause. Six of our current executive officers are experienced Petrobras career managers, engineers or technicians.

The following table sets forth certain information with respect to our executive officers:

Name	**Date of Birth**	**Position**	**Current Term**
Maria das Graças Silva Foster	August 26, 1953	Chief Executive Officer and Chief International Officer(1)	April 2014
Almir Guilherme Barbassa	May 19, 1947	Chief Financial Officer and Chief Investor Relations Officer	April 2014
José Antonio De Figueiredo	January 1, 1956	Chief Engineering, Technology and Procurement Officer	April 2014
José Miranda Formigli Filho	March 30, 1960	Chief Exploration and Production Officer	April 2014
José Carlos Cosenza	April 23, 1951	Chief Downstream Officer	April 2014
José Alcides Santoro Martins	August 28, 1954	Chief Gas and Power Officer	April 2014
José Eduardo de Barros Dutra	April 11, 1957	Chief Corporate and Services Officer	April 2014

(1) On July 23, 2012, the Board of Directors acknowledged the resignation of Petrobras' Chief International Officer, Jorge Luiz Zelada, and appointed the Chief Executive Officer, Maria das Graças Silva Foster, in charge of such duties.

Maria das Graças Silva Foster—Ms. Foster has been our Chief Executive Officer since February 13, 2012. For biographical information regarding Ms. Foster, see "—Directors."

Almir Guilherme Barbassa—Mr. Barbassa has been our Chief Financial Officer and Chief Investor Relations Officer since July 22, 2005. Mr. Barbassa joined Petrobras in 1974 and has worked in several financial and planning capacities, both in Brazil and abroad. Mr. Barbassa has served as Petrobras' corporate finance and treasury manager, and he has also served at various times as financial manager and chairman of Petrobras subsidiaries that carry out international financial activities. Mr. Barbassa is also a member of the board of directors of Braskem S.A. In addition, he was an economics professor at Universidade Católica de Petrópolis (Petrópolis Catholic University) and Faculdades Integradas Bennett (Bennett University) from 1973 to 1979. Mr. Barbassa holds a master's degree in economics from the Fundação Getúlio Vargas (Getulio Vargas Foundation).

José Antonio De Figueiredo— Mr. Figueiredo has been our Chief Engineering, Technology & Procurement Officer since May 16, 2012. Mr. Figueiredo joined Petrobras in 1979 and has held various management positions at Petrobras' research center and engineering department before being appointed as General Manager of our E&P and Shipbuilding Projects in February 2001, E&P-Southeast Area Executive Manager in 2003, Services Executive Manager at E&P segment in February 2012 and Engineering Executive Officer in May 2012. Mr. Figueiredo holds a degree in electronic engineering from the Universidade Federal do Rio de Janeiro – UFRJ (Federal University of Rio de Janeiro) and an MBA in business management from the Fundação Getúlio Vargas (Getulio Vargas Foundation).

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José Miranda Formigli Filho—Mr. Formigli Filho has been our Chief Exploration and Production Officer since February 2012. Mr. Formigli Filho graduated in civil engineering from the Instituto Militar de Engenharia—IME, with a specialization in petroleum engineering and has an MBA in advanced business management from the Universidade Federal do Rio de Janeiro—COPPEAD. He is a member of the Society of Petroleum Engineers (SPE) and the Society for Underwater Technology (SUT). In Petrobras' E&P segment, he has managed offshore activities and has been the Production Manager of the Campos Basin, Marlim Field Asset Manager, Services Executive Manager and Production Engineering Executive Manager. From May 2008 through January 2012, Mr. Formigli Filho was the Executive Manager of Pre-Salt Development.

José Carlos Cosenza—Mr. Cosenza has been our Chief Downstream Officer since April 2012. Mr. Cosenza joined Petrobras in 1976 and worked as Production Manager at REFAP (Refinaria Alberto Pasqualini), General Manager at both REPAR (Refinaria do Paraná) and REPLAN (Refinaria de Paulínia) and was the Chief Executive Officer of Petrobras Argentina and Petrobras Uruguay. He was the Vice President of the expansion project of Pasadena Refinery in the United States and Executive Manager of Refining. Mr. Cosenza holds a degree in chemical engineering from the Universidade Federal do Rio Grande do Sul (Federal University of Rio Grande do Sul).

José Alcides Santoro Martins—Mr. Santoro Martins has been our Chief Gas and Power Officer since February 2012. Mr. Santoro Martins holds a bachelor's degree in civil engineering from the University of São Paulo—USP. He has been at Petrobras for 33 years and has held various management positions, as well as being a board member of different subsidiaries of the Company. He is also Chief Executive Officer of Petrobras Gas S.A. since March 2012. He was the Chief Executive Officer of Termobahia S.A. from September 2008 to March 2012, of Termoceará Ltda., Termomacaé Ltda. and Sociedade Fluminense de Energia Ltda. from October 2008 to April 2012, of Fafen Energia S.A. from September 2008 to December 2011; of Termorio S.A. from August 2008 to December 2011; and of UTE Bahia I Camaçari Ltda. from September 2008 to December 2011. He was also Director for Oil, Gas and Biofuels at the Energy Research Company—(Empresa de Pesquisa Energética, EPE) from May 2005 to June 2006 and Technology Director at the Center for Gas & Renewable Energy Technology—CTGAS-ER from February 2004 to May 2005. Mr. Santoro is the Chairman of the Board of Transportadora Associada de Gás S.A. and a full member of the board of directors of Petrobras Gas S.A., Petrobras Transportes S.A. and Braskem S.A.

José Eduardo de Barros Dutra—Mr. Dutra has been our Chief Corporate and Services Officer since March 1, 2012. Mr. Dutra received a degree in geology from the Universidade Federal Rural do Rio de Janeiro (Federal Rural University of Rio de Janeiro) in 1979. In 1994, he was elected Senator of the Republic with a mandate from 1995 to 2002. He was the CEO of Petrobras from January 2003 to July 2005, and held the post of Director of Petrobras and Director of Petrobras Distribuidora S.A. He was CEO of Petrobras Distribuidora S.A. – BR from September 2007 to August 2009, and also worked as a geologist at Petrobras Mineração S.A. –

Petromisa from 1983 to 1990 and at Vale from 1990 to 1994. In addition, Mr. José Eduardo was chairman of the Board of Directors of Petrobras Gás S.A. – Gaspetro, Petrobras Transporte S.A. – Transpetro, Petrobras Química S.A. – Petroquisa, Petrobras Energia S.A. – Pesa and Liquigás Distribuidora S.A.

Compensation