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we are.

GranTierra
energy inc.

Production

LIGHT OIL AND MEDIUM OIL AND LIQUIDS PRODUCED IN 2011

96%

2011 PRODUCTION

17,408
BOEPD NAR

2011 oil and natural gas production averaged 17,408 BOEPD NAR. Improved production from the Moqueta, Jilguero and Juanambu Fields and Petrolifera's production contributed to this 20% increase when compared with 2010.

Reference to annual production is adjusted for changes in inventory. Unless otherwise noted, acreage is at year end 2011.

Exploration

2012 GROSS EXPLORATION WELLS

11

YEAR END 2011 NET ACRES

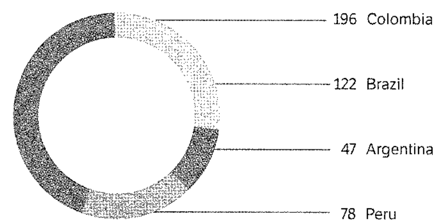
7.0MM

2012 PRODUCTION GOAL

20,000

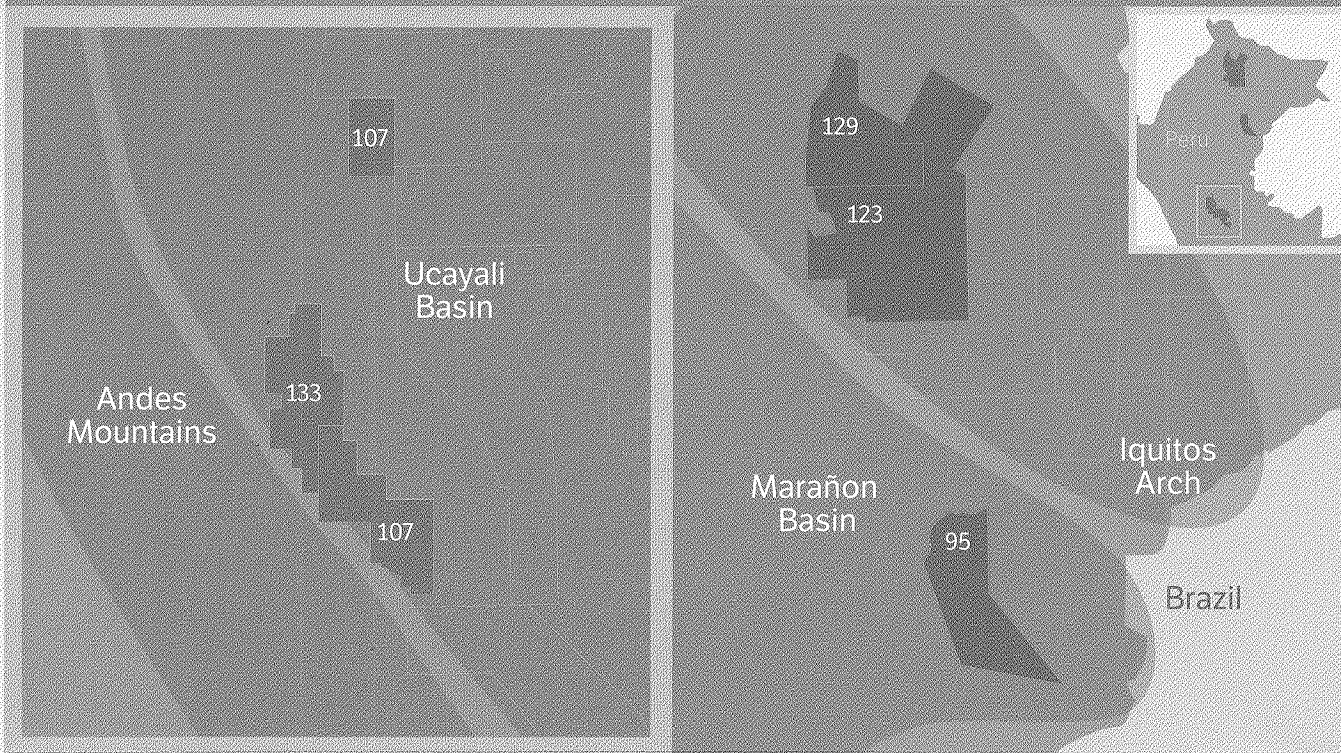
BOEPD NAR

2012 EXPLORATION & DEVELOPMENT
($ MILLIONS)



Gran Tierra Energy plans to drill 28 wells in 2012, with a $444 million planned capital program for its exploration and production operations in Colombia, Brazil, Peru and Argentina. Excluding potential exploration success, production in 2012 is expected to range between 20,000 to 21,000 BOEPD NAR.

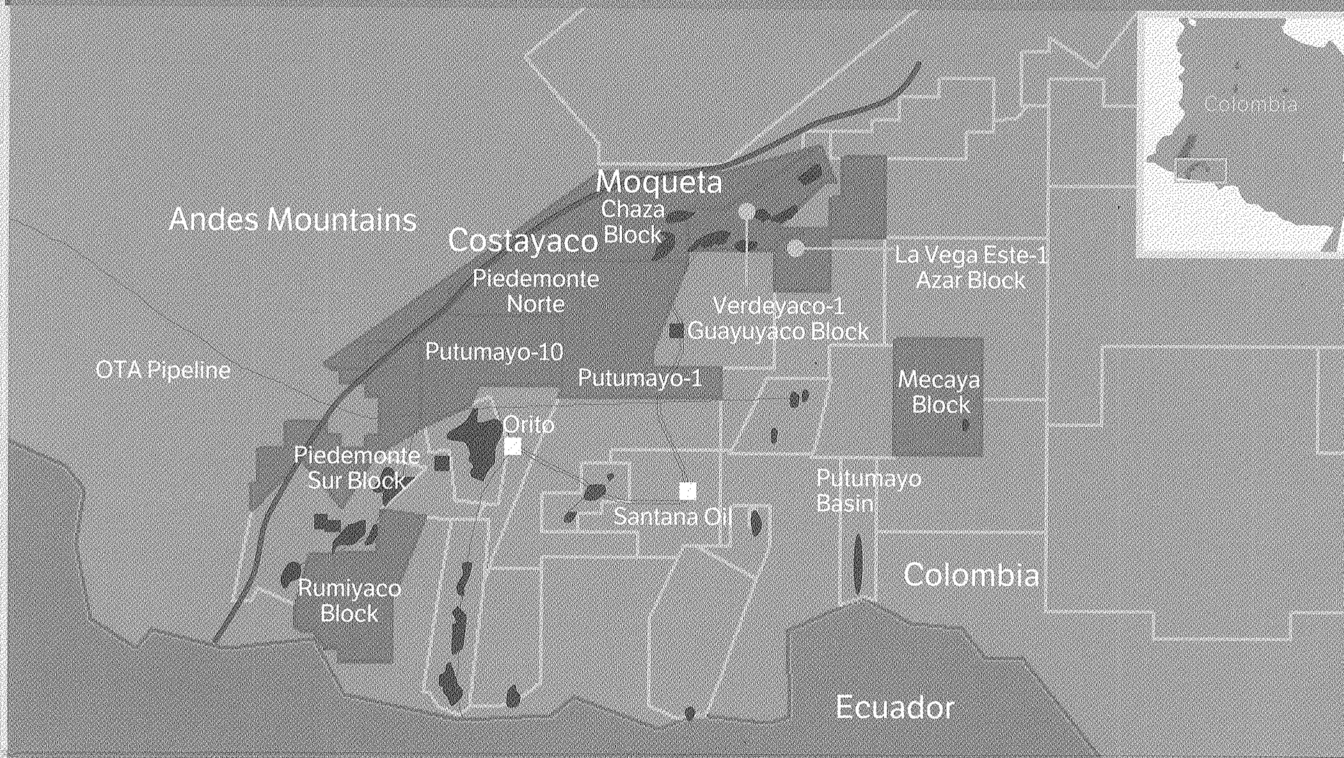
PERU



Gran Tierra Energy's operated Block 95 has a total area of 1,274,399 gross acres. A drilling location has been identified for the first exploration well on Block 95. Drilling is expected to begin in 2012, pending regulatory approvals. The new exploration well is expected to further delineate the previously discovered oil field and explore deeper reservoir horizons not penetrated by the original discovery well drilled in 1974.

Gran Tierra Energy has a 20% working interest in Block 123 and Block 129, which cover 3,491,240 gross acres. Burlington Resources Peru Limited (a wholly owned subsidiary of ConocoPhillips) is the operator of these blocks. In 2011, 910 kilometers of 2D seismic was acquired on these blocks. In 2012, we plan to acquire 567 kilometers of 2D seismic.

We acquired our 100% working interest in our operated Blocks 107 and 133 through the Petrolifera acquisition in March 2011. Combined, these Blocks cover 1,602,167 gross acres. In 2011, we conducted environmental studies and advanced permitting for drilling. In 2012, we plan to complete a 390 kilometer infill 2D seismic program and begin preparations for drilling in 2013.

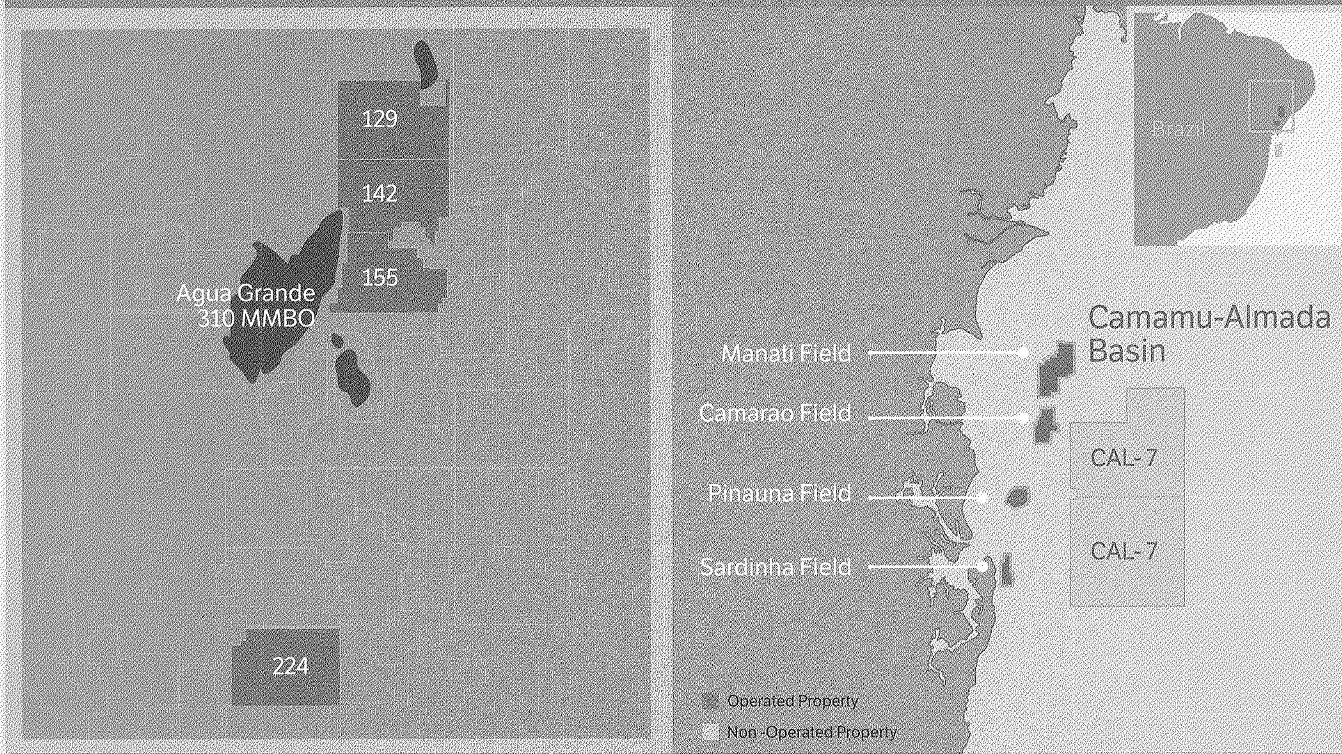


In 2011, we drilled and completed three development wells in the Costayaco Field and three development wells in the Moqueta field. During 2011, we commenced construction of facilities at the Moqueta field and completed the six-inch diameter, eight kilometer pipeline connecting the Moqueta and Costayaco infrastructure. A parallel four-inch gas line was also completed that will be used to transport gas or water from Costayaco to Moqueta for anticipated injection for pressure support. In 2012, we plan to drill seven gross development wells: two water injector and two production wells in the Costayaco field, one development and one water injector well in the Moqueta field, and a natural gas delineation well on the Sierra Nevada Block.

In our operated Guayuyaco Block (70% participation interest), we drilled the Juanambu-3 development well as a producing well, purchased pumping equipment and acquired the Verdayaco prospect 3D seismic in 2011. In 2012, we plan to drill the Verdayaco-1 oil exploration well.

On the Garibay Block, the Melero-1 exploration well was drilled and completed, resulting in an oil discovery. The Jilguero-2 development well was also completed as a producing well in October 2011. In 2012, together with CEPSA, we plan to drill the Bordon-1 oil exploration well.

In 2011, we conducted environmental studies on the Azar Block. In 2012, we plan to drill the La Vega Este-1 oil exploration well.

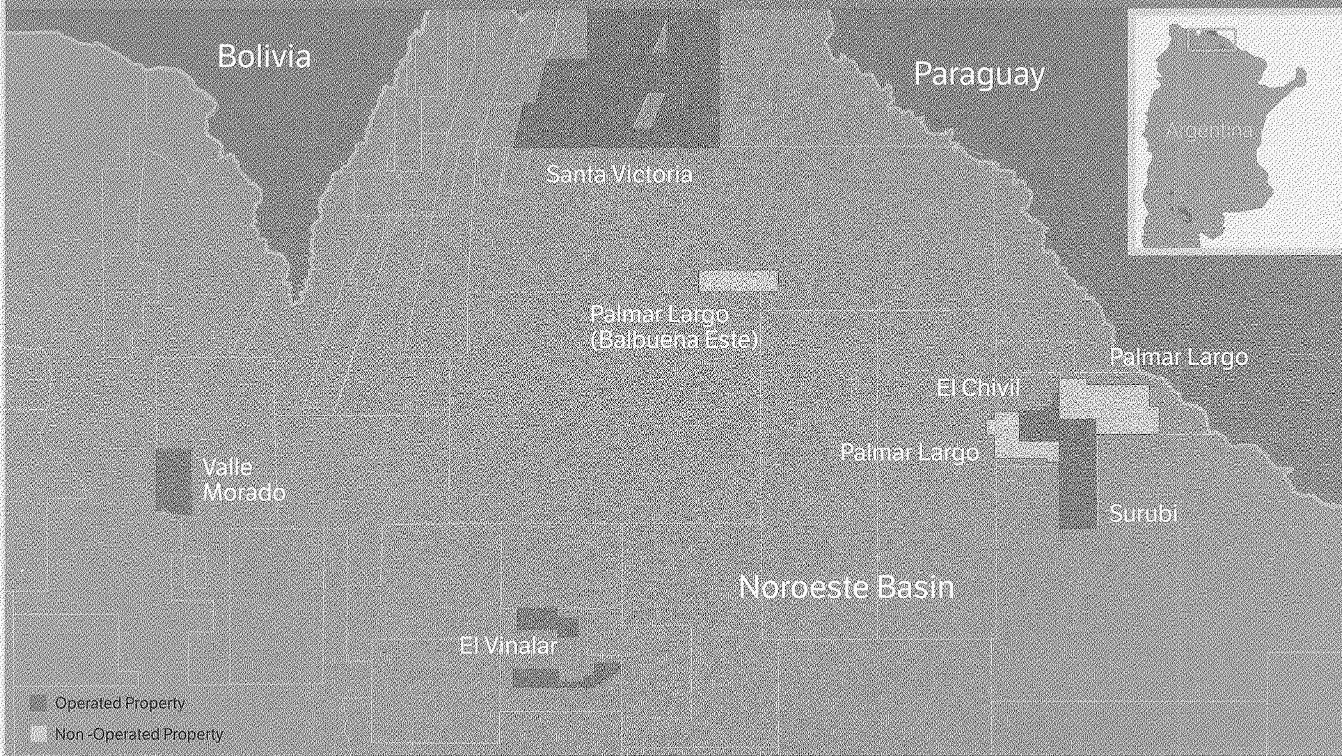


Gran Tierra Energy has a 70% working interest in each of four onshore operated blocks in Brazil. Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 are located approximately 70 kilometers northeast of Salvador, Brazil in the Recôncavo Basin, and cover 27,075 gross acres. On January 20, 2012, we entered into a purchase and sale agreement to acquire the remaining 30% participating interest in Blocks 129, 142, 155 and 224 subject to ANP approval.

Drilling activities initiated in 2011 include one gross exploration and one vertical pilot exploration well on Block REC-T-142, one appraisal and one delineation well on Block REC-T-155, and one gross exploration well on REC-T-129. Drilling of the exploration well on Block REC-T-129 is suspended while plans are finalized for drilling a horizontal leg in mid-2012. On Block REC-T-155, an additional development well began in January 2012 to further develop the existing discovery. Oil bearing reservoir intervals were encountered and we are moving forward with plans to complete and place this well on production.

Gran Tierra Energy completed the acquisition of 35 square kilometers of 3D seismic data on Block REC-T-224. In 2012, we completed two appraisal wells on Block REC-T-155 and plan to drill three horizontal exploration wells on Blocks REC-T-155, REC-T-142 and REC-T-129, in 2012. The non-operated offshore BM-CAL-7 Block (10% working interest) is located in the Camamu Basin in Bahia, Brazil, and covers 337,561 gross acres.

ARGENTINA



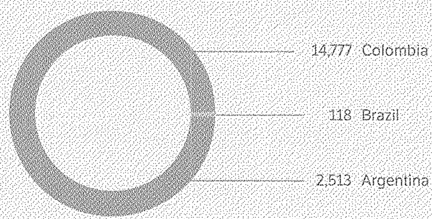
In March 2011, Gran Tierra Energy acquired Petrolifera which added seven blocks in the Neuquen basin: Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Vaca Mahuida, and Puesto Guevara. The Rinconada Sur Block is part of the Puesto Morales concession. Gran Tierra Energy relinquished our position in the Gobernador Ayala II Block in 2011.

The Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Surubi, El Chivil, Palmar Largo and El Vinalar blocks have producing oil wells and Puesto Morales also has producing gas wells.

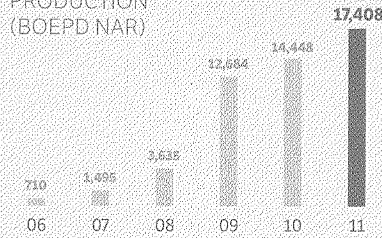
In 2011, we commenced facilities upgrades, the drilling of two development wells, and a well workover program on the Puesto Morales Block. We plan to drill seven development wells in 2012 and continue with the workover program and facilities upgrades. Gran Tierra Energy has no outstanding work commitments on this Block.

The Rinconada Sur Block covers 28,417 gross acres and is part of the Puesto Morales concession. Gran Tierra Energy began drilling one development well in 2011 which is on production, along with the drilling of two exploration wells and completion of geological and geophysical subsurface work.

2011 PRODUCTION
(BOEPD NAR)



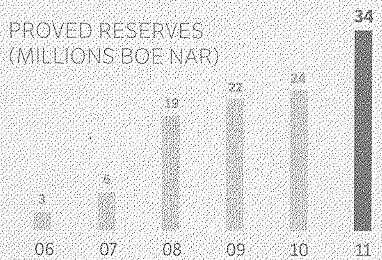
PRODUCTION
(BOEPD NAR)

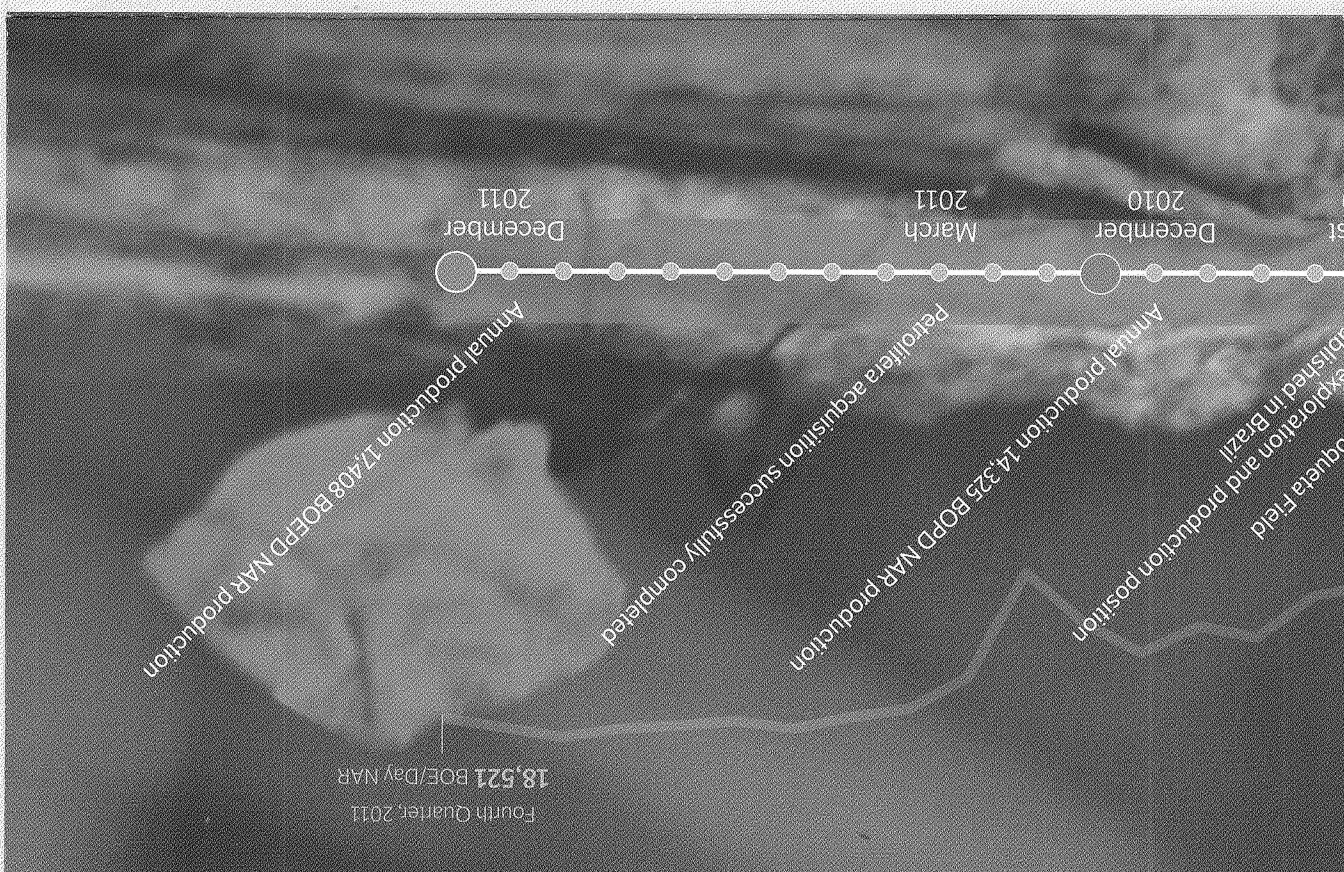


2011 PROVED RESERVES

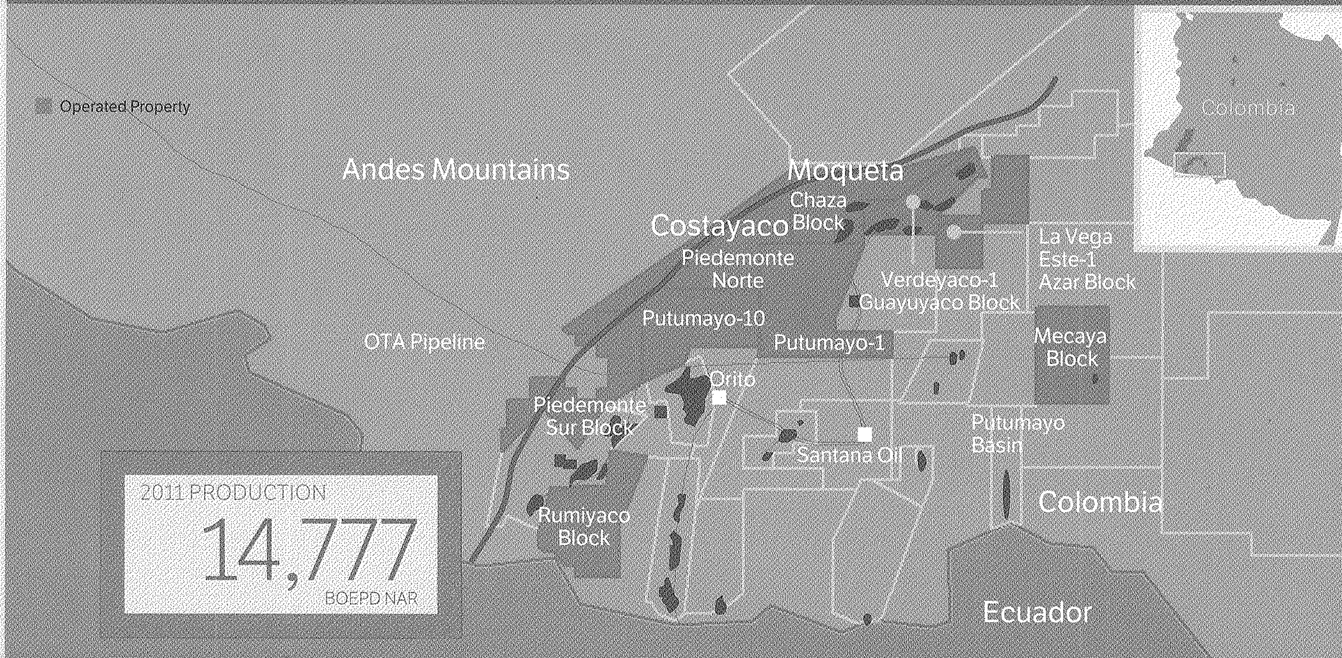
34MM
BOE NAR

PROVED RESERVES
(MILLIONS BOE NAR)

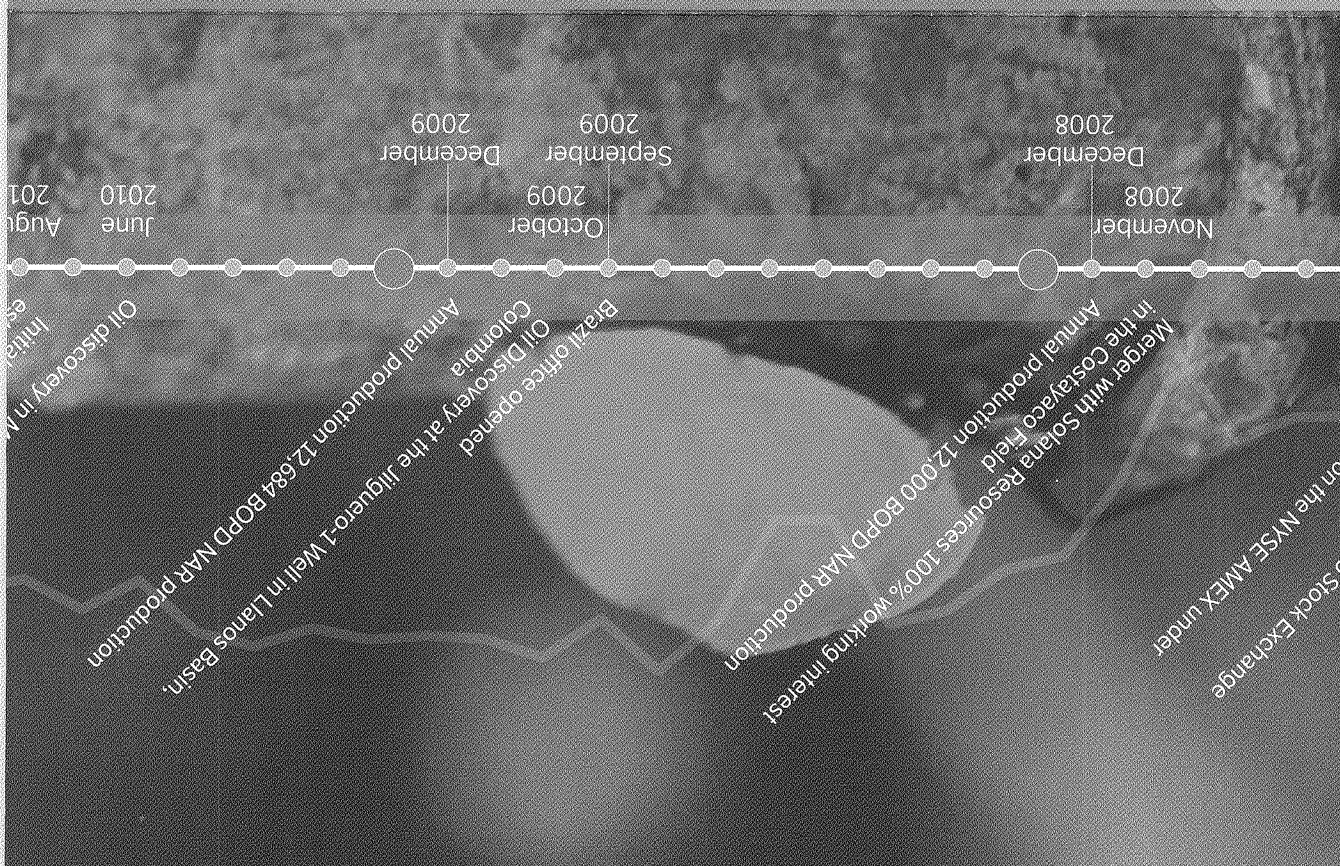




COLOMBIA

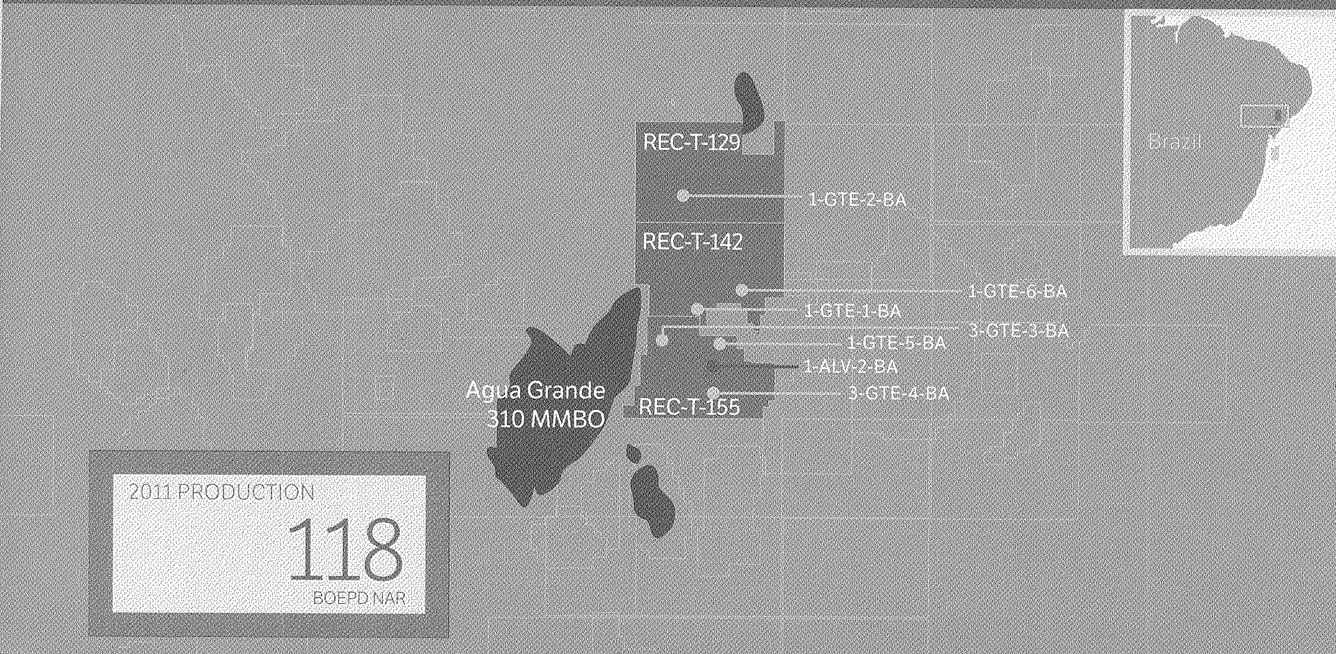


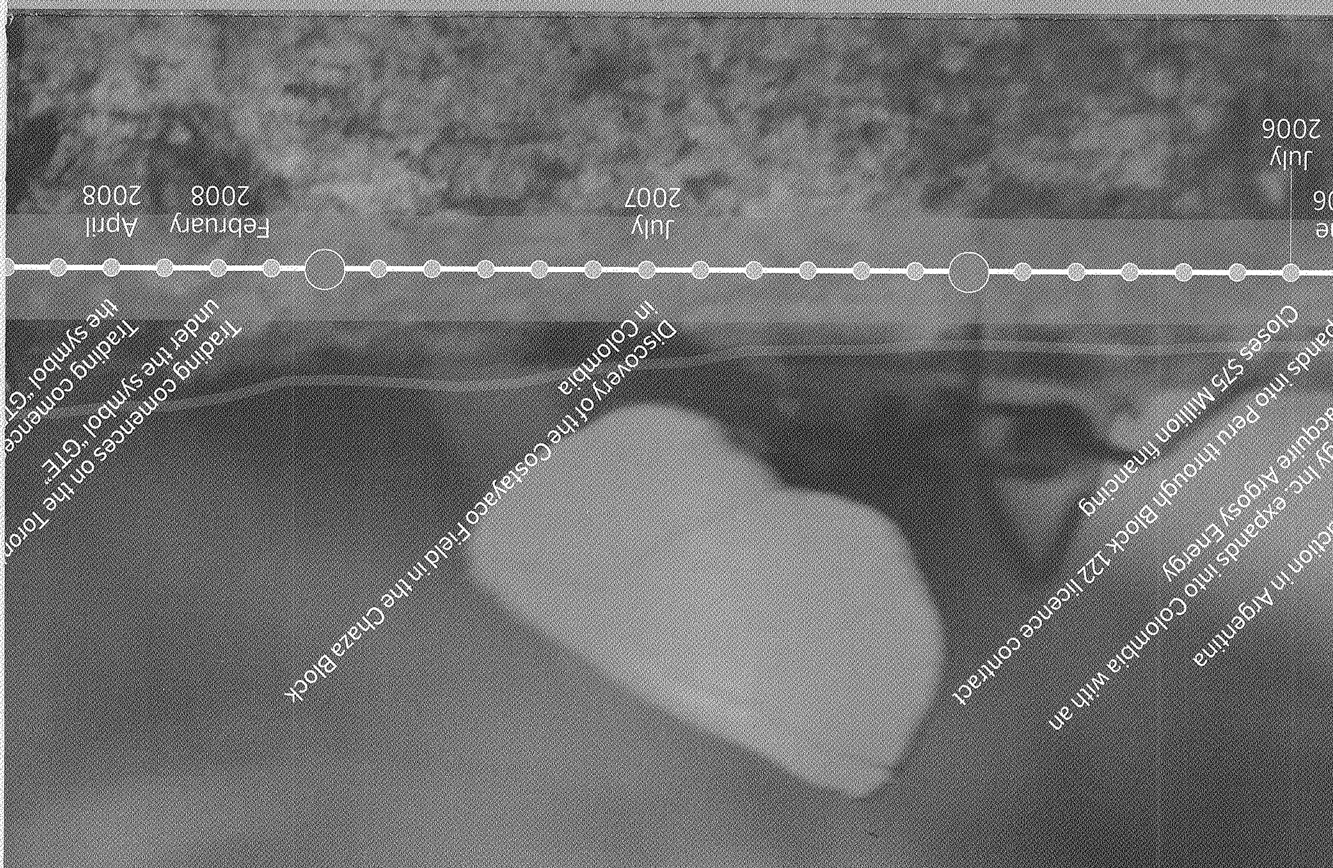
Operated Property
Andes Mountains
Moqueta
Chaza Block
Costayaco
Piedemonte Norte
La Vega Este-1
Azar Block
Verdeyaco-1
Guayuyaco Block
Putumayo-10
OTA Pipeline
Putumayo-1
Mecaya Block
Orito
Piedemonte Sur Block
Santana Oil
Putumayo Basin
Colombia
Rumiyaco Block
Ecuador
2011 PRODUCTION
14,777
BOEPD NAR



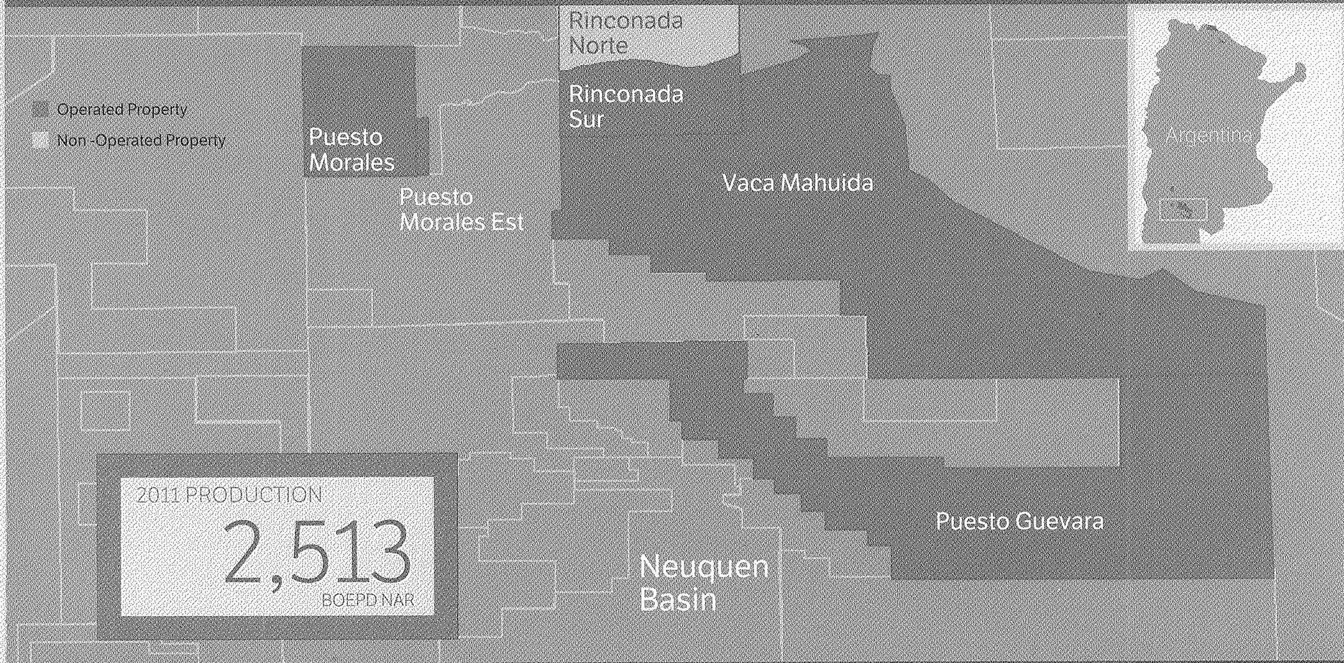
November 2008
Merger with Solana Resources 100% working interest in the Costayaco Field
December 2008
Annual production 12,000 BOPD NAR production
September 2009
Brazil office opened
October 2009
Oil Discovery at the Jiguero-1 Well in Llanos Basin, Colombia
December 2009
Annual production 12,684 BOPD NAR production
June 2010
on the NYSE AMEX under
o Stock Exchange

BRAZIL

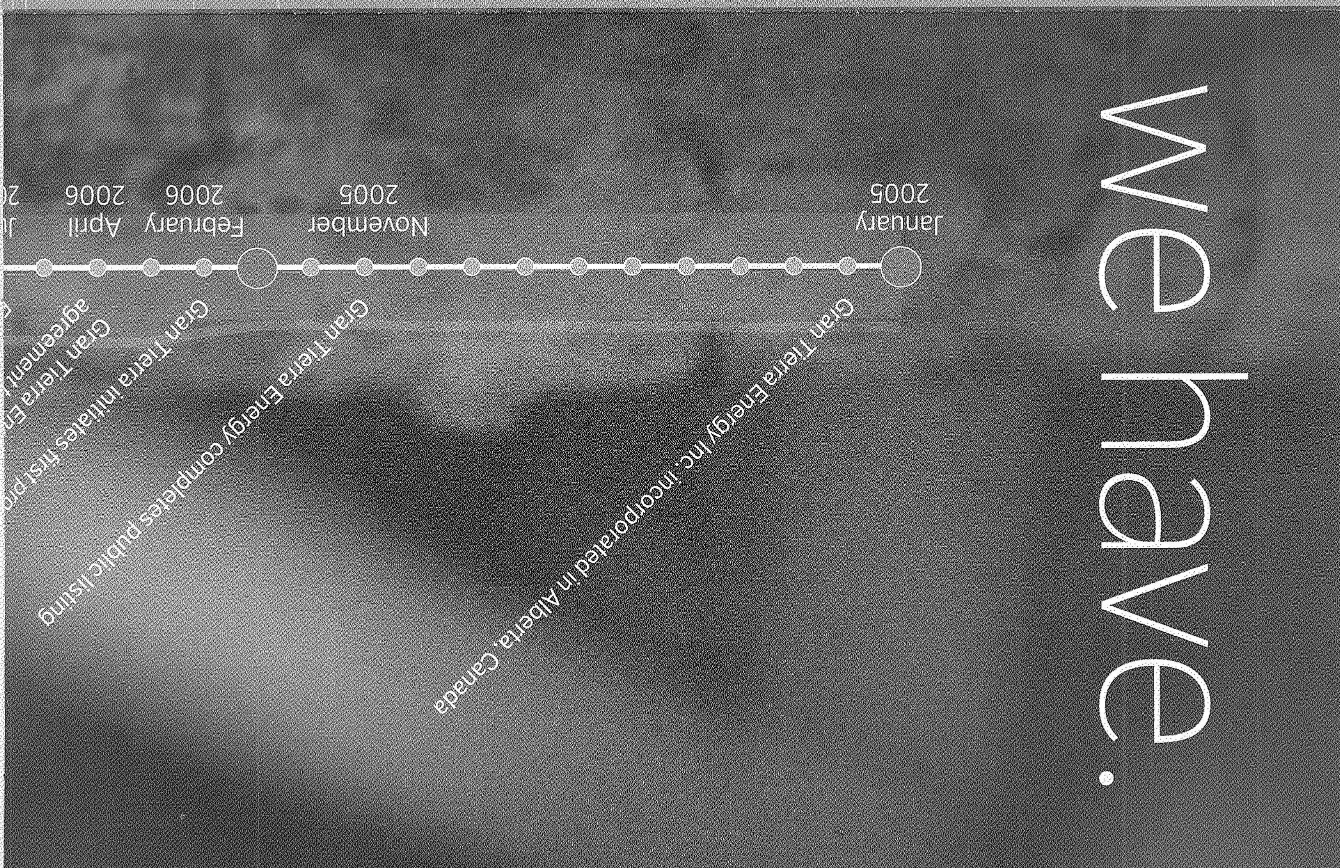

Brazil
REC-T-129
1-GTE-2-BA
REC-T-142
1-GTE-6-BA
1-GTE-1-BA
3-GTE-3-BA
1-GTE-5-BA
1-ALV-2-BA
3-GTE-4-BA
Agua Grande
310 MMBO
REC-T-155
2011 PRODUCTION
118
BOEPD NAR


July
2006
July
2007
February
2008
April
2008
Closes $75 Million financing
Expands into Peru through Block 122 licence contract
Discovery of the Costayaco Field in the Chaza Block
in Colombia
Trading comences on the Toron
under the symbol "GTE"

ARGENTINA

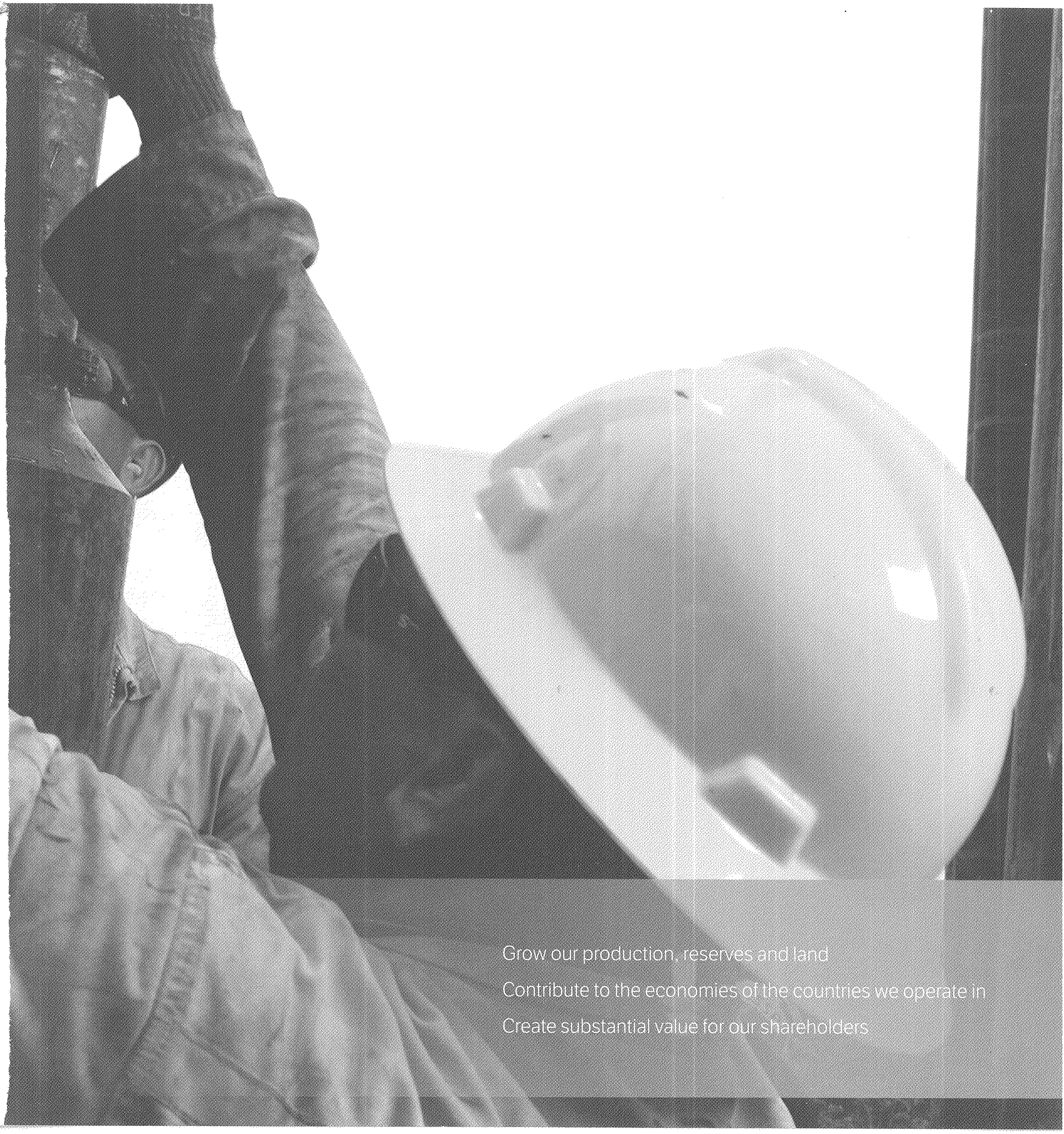


Operated Property
Non -Operated Property
Rinconada Norte
Rinconada Sur
Puesto Morales
Puesto Morales Est
Vaca Mahuida
Argentina
2011 PRODUCTION
2,513
BOEPD NAR
Puesto Guevara
Neuquen Basin



we have.
January 2005
Gran Tierra Energy Inc. incorporated in Alberta, Canada
November 2005
Gran Tierra Energy completes public listing
February 2006
April 2006


we can...


Grow our production, reserves and land
Contribute to the economies of the countries we operate in
Create substantial value for our shareholders

Gran Tierra Energy 2011 at a Glance

EXPLORATION ACRES

12.1MM
GROSS ACRES

PROVED RESERVES

34.0MM
BOE NAR

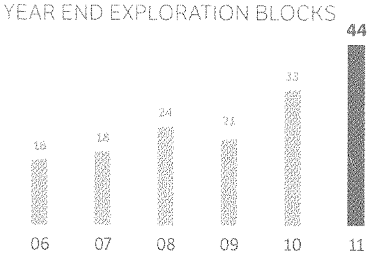
PRODUCTION

17,408
BOEPD NAR

All Reserve figures contained in this document are SEC compliant as of December 31, 2011.
Reference to annual production is adjusted for changes in inventory.
Exploration blocks, producing wells and acreage area at year end 2011 unless otherwise noted

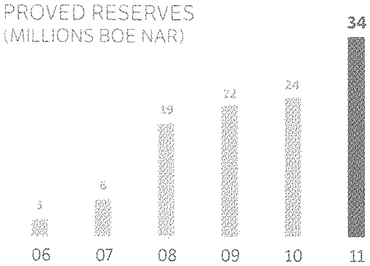
Gran Tierra Energy was formed to capitalize on the expertise, experience and strategic relationships of the management team to build sustainable value and a record of success in South America. Our mission is to create value, sensibly and aggressively, in oil and gas exploration and production.

YEAR END EXPLORATION BLOCKS

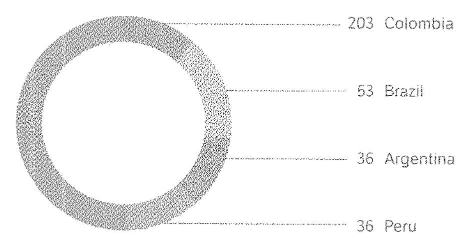


96% LIGHT AND MEDIUM OIL AND LIQUIDS PRODUCED IN 2011

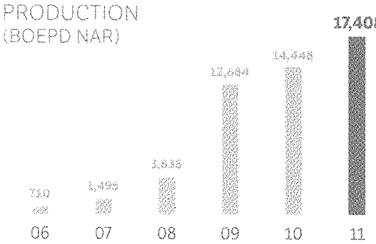
PROVED RESERVES
(MILLIONS BOE NAR)



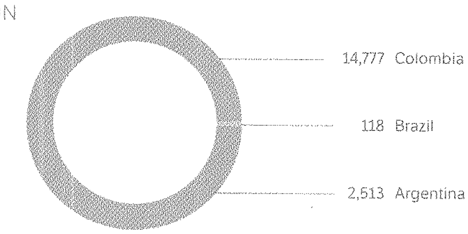
2011 EXPLORATION & DEVELOPMENT
($ MILLIONS)



PRODUCTION
(BOEPD NAR)



2011 PRODUCTION
(BOEPD NAR)



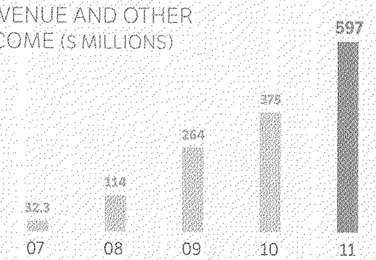
2011 Financial Highlights

2011 was another year that we achieved record production, revenues, net income and funds flow from operations. Our formula for success positions Gran Tierra Energy to fund its entire 2012 capital program from cash on hand and cash flow, at current commodity prices and production levels.

REVENUE AND OTHER INCOME

$597.4MM ↑60%

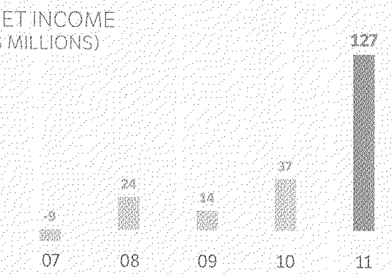
REVENUE AND OTHER INCOME ($ MILLIONS)



NET INCOME

$126.9MM ↑241%

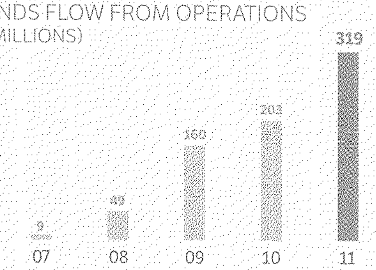
NET INCOME ($ MILLIONS)



FUNDS FLOW FROM OPERATIONS*

$319.0MM ↑57%

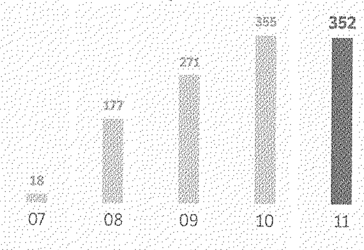
FUNDS FLOW FROM OPERATIONS ($ MILLIONS)



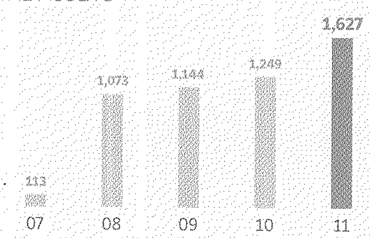
*Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under generally accepted accounting principles in the United States of America ("GAAP"). A reconciliation to net income and additional disclosure can be found on page 38.

($ MILLIONS)

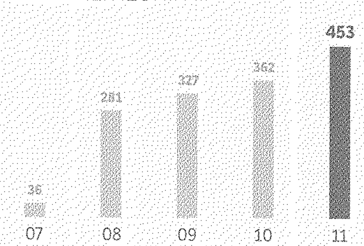
CASH AND CASH EQUIVALENTS



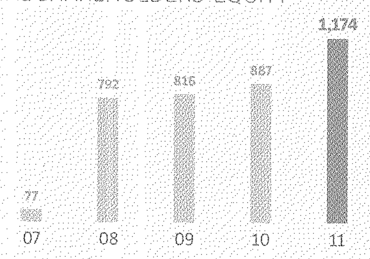
TOTAL ASSETS



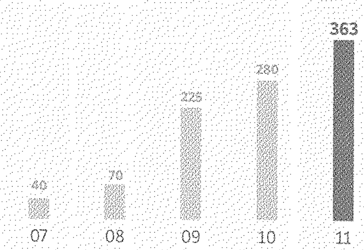
TOTAL LIABILITIES



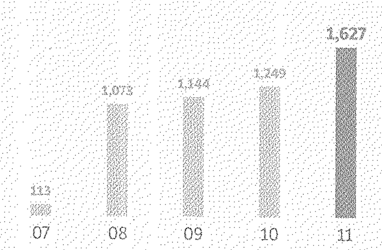
TOTAL SHAREHOLDERS' EQUITY



TOTAL EXPENSES



TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY



Exploration at a Glance

Gran Tierra Energy remains committed to its strategy through 2012, a strategy that has consistently grown land, reserves and production year over year for the last six years. Our focus on execution sees the company entering 2012 with a robust exploration portfolio and a balanced mix of development drilling and exploration drilling.

2012 CAPITAL PROGRAM

$444.0MM

2011 FUNDS FLOW FROM OPERATIONS*

$319.0MM

2011 NET INCOME

$126.9MM

2012 GROSS EXPLORATION WELLS

11

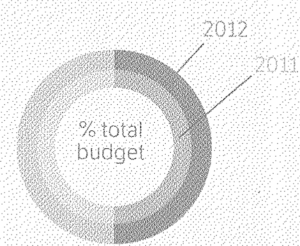
2012 PRODUCTION GOAL

20,000-21,000 BOEPD NAR

*Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under generally accepted accounting principles in the United States of America ("GAAP"). A reconciliation to net income and additional disclosure can be found on page 38.

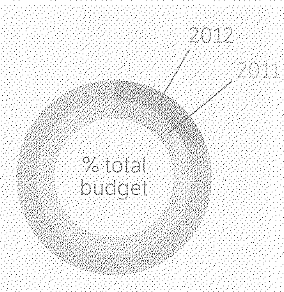
2012 CAPITAL PROGRAM*

Colombia



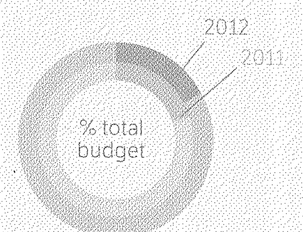
$196MM

Brazil



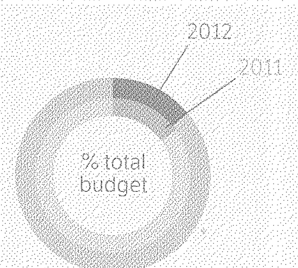
$122MM

Peru



$78MM

Argentina



$47MM

*2012 Capital program of $444 million includes $1 million assigned to corporate activities.


we have...

Built substantial value in South America

Created a high-performance culture

Established effective local presence in the countries in which we operate

EXPLORATION

Colombia

The Colombia capital budget for 2012 is $196 million and is expected to include drilling of four gross exploration wells and seven gross development wells primarily focused in the Putumayo and Llanos basins. These two basins provided our most recent exploration success, in the Chaza block with the Moqueta field discovery in 2010 and in the Garibay block with the Melero field discovery in 2011.

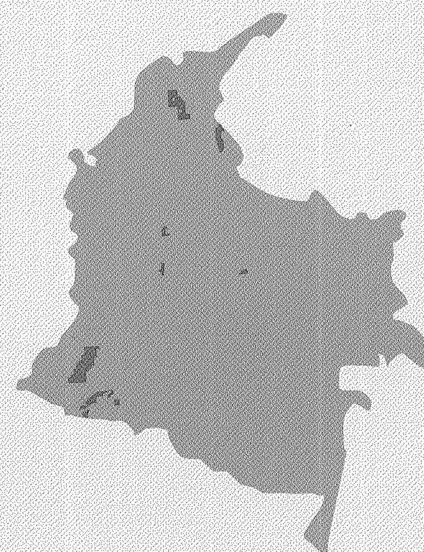
BLOCKS	2012 GROSS EXPLORATION WELLS	GROSS ACRES	NET ACRES
21	4	3.5 MM	3.1 MM

Gran Tierra Energy's oil exploration drilling program includes four gross exploration wells on prospects in the Putumayo and Llanos Basins. The company has allocated $107 million to drilling activities in 2012. Based on drilling that commenced on the Ramiriqui-1 oil exploration well in the fourth quarter of 2011, the Mirador formation has been interpreted as oil bearing. On April 11, 2012, Gran Tierra Energy announced a successful flow test of the Ramiriqui-1 exploration well at 2,525 BOPD.

Gran Tierra Energy plans on drilling the Bordon-1 oil exploration well to the north of the Melero and Jilguero discoveries on the Garibay Block, the Verdeyaco -1 oil exploration well on the Guayuyaco Block and the La Vega Este-1 oil exploration well on the Azar Block in 2012.

Development and delineation activities for 2012 will focus on the Moqueta, Costayaco and Brillante field developments and includes drilling of seven gross development wells. The company plans to drill two water injector wells and two production wells in the Costayaco field; and one development well and one water injector well in the Moqueta field. Gran Tierra Energy also plans on drilling the Brillante -3 natural gas delineation well in the Sierra Nevada Block.

Planned facilities work, for which Gran Tierra Energy has allocated $37 million in 2012, includes continued electrification of the Moqueta field and water injection facilities and a production battery at the Jilguero oil discovery. Planned geological and geophysical ("G&G") work, for which the company has allocated $52 million in 2012, consists of 427 km2 of 3D seismic and 201 km of 2D seismic for the Chaza, Garibay, Piedmonte Norte, Piedmonte Sur, Llanos-22, Putumayo-1 and Putumayo-10 Blocks.



Colombian blocks and acreage include those pending regulatory approval

PRODUCTION

Colombia

GROSS PRODUCING WELLS

41

INCREASE IN DAILY AVERAGE PRODUCTION

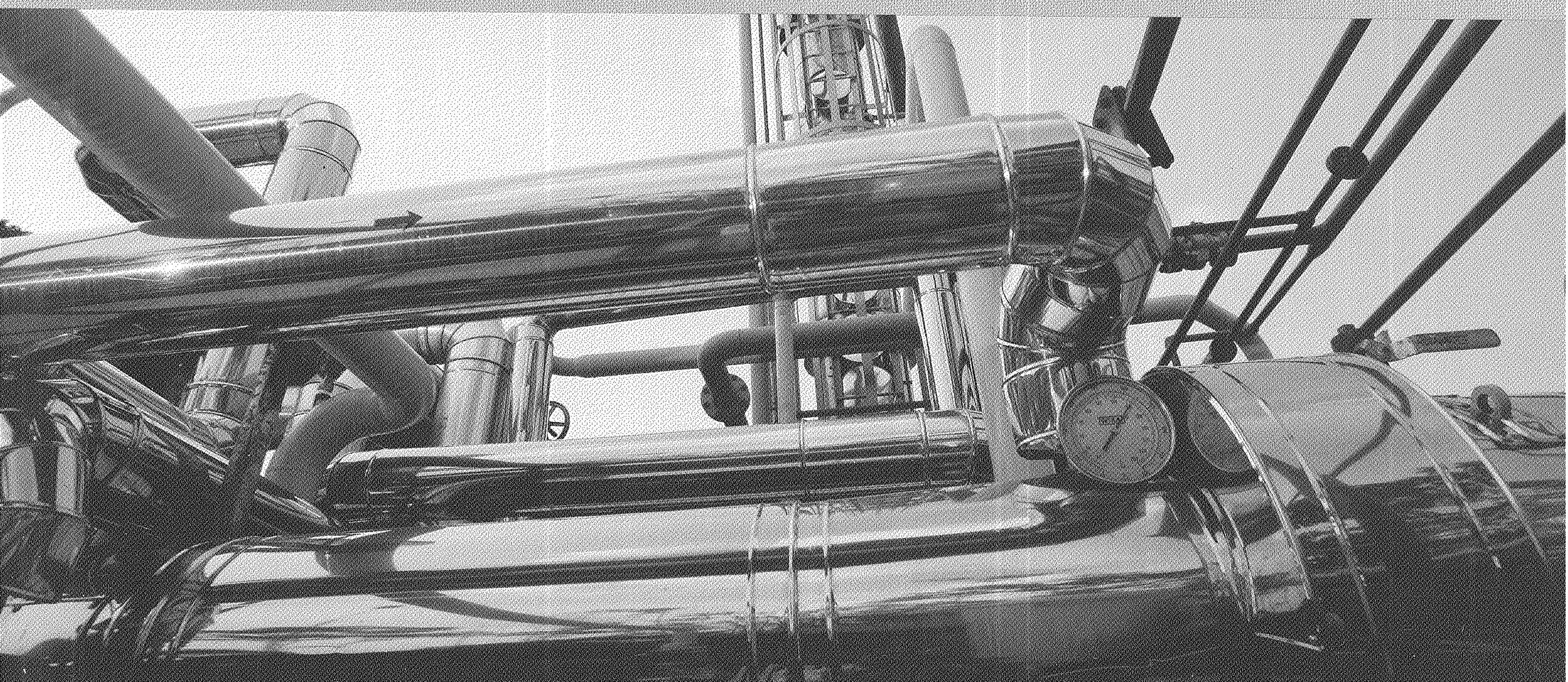
↑8%

PRODUCTION

14,777

BOEPD NAR

Gran Tierra Energy continued to build on its robust platform in Colombia with the addition of production from its Moqueta field and an oil discovery on the Garibay block with the Melero-1 exploration well. Gran Tierra Energy's core holdings in Colombia are in the Putumayo Basin where we continue to be the number one land holder, reserve holder, and producer. In 2011, the company grew its reserves and production through new discoveries, along with further development of the Moqueta field and continued waterflood at our Costayaco field.



"In 2011, we significantly increased production and added to our reserve base in Colombia through further development in the Putumayo and Llanos Basins. Gran Tierra Energy Colombia also continued to strengthen its exploration portfolio and has set the stage for future exploration success and production growth through a farm-in to high potential exploration acreage which has resulted in initial 2012 exploration success in the Llanos Basin."

Duncan Nightingale, President
Gran Tierra Energy Colombia

PROVED RESERVES (NAR)

27.9 MMBOE

PROVED + PROBABLE (NAR)

37.3 MMBOE

PROVED + PROBABLE + POSSIBLE (NAR)

59.1 MMBOE

EXPLORATION

Brazil

The Brazil capital budget for 2012 is $122 million and is expected to include drilling of three gross horizontal sidetrack wells.

BLOCKS*	2012 GROSS EXPLORATION WELLS	GROSS ACRES	NET ACRES (000)*
5	3	365	53

In 2011, Gran Tierra Energy added to its interests in four blocks in the onshore Recôncavo Basin by entering its first offshore partnership, in the Camamu-Almada Basin, with a 10% working interest in a farmout agreement with Statoil, in a partnership that also includes Petrobras.

The Brazil capital budget for 2012 is $122 million and will focus on the Recôncavo Basin, where Gran Tierra Energy plans to drill three horizontal sidetracks, including one from the recently completed 1-GTE-01-BA pilot hole, and two gross development wells. Including the cost of the recent offshore well on Block BM-CAL-10, $107 million has been allocated to drilling and acquisitions in 2012. Approximately $12 million has been allocated to pipelines and facilities, and an additional $3 million for G&G work. Planned facilities work includes additional tankage, pipelines and gas facilities on Block 155.

Brazil's exploration program could increase to seven gross exploration wells in 2012 with success from the planned initial horizontal drilling program.

*As of February 27, 2012 and includes relinquishment of the BM-CAL-10 Block.

PRODUCTION

Brazil

GROSS PRODUCING WELL

1

INCREASE IN DAILY AVERAGE PRODUCTION

TWO NEW PRODUCTION WELLS DRILLED IN 2012

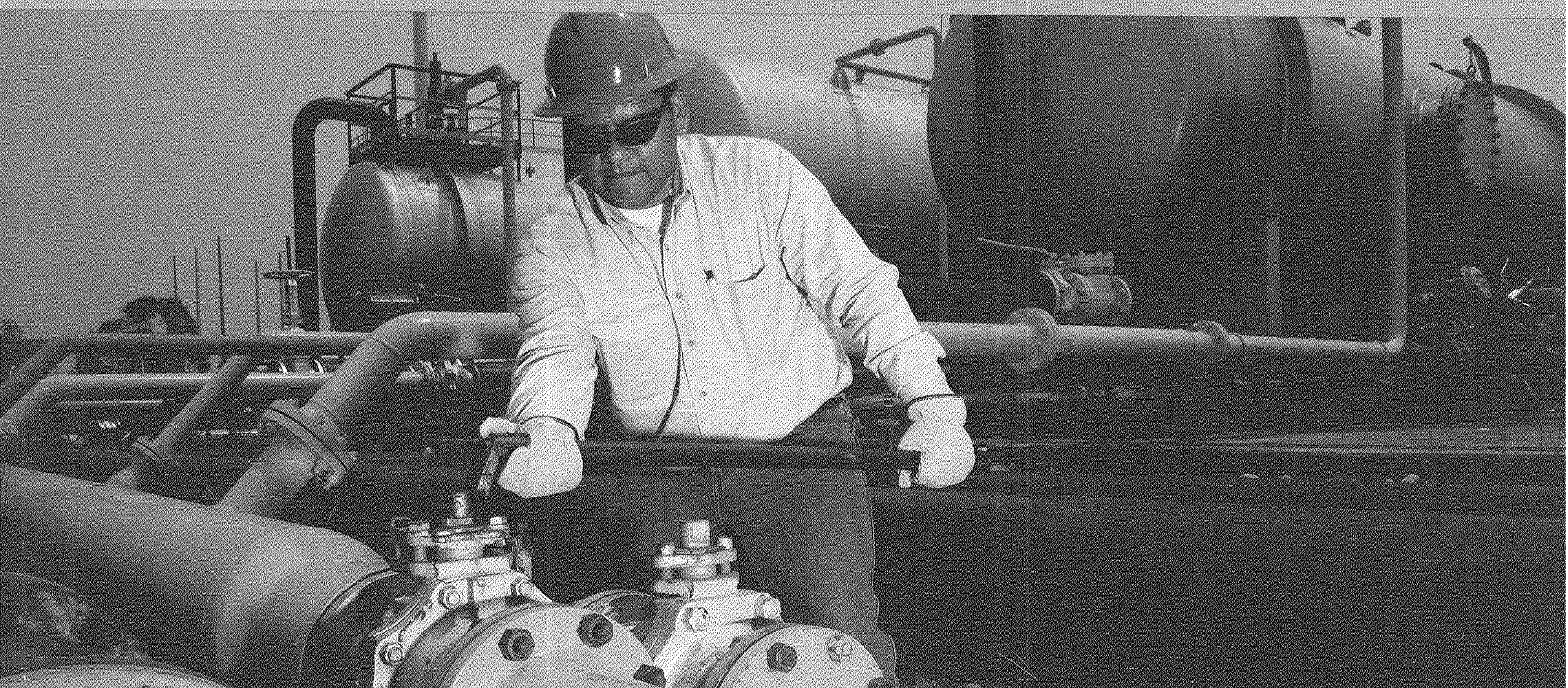
2011 PRODUCTION

118

BOEPD NAR

Gran Tierra Energy's successful growth in South America has been driven by our ability to identify underdeveloped land in countries that provide a favorable environment for independent oil and gas exploration companies. Our 2011 accomplishments in Brazil are further proof of this strategy.

Building on our successful business development office in Rio de Janeiro in 2010, Gran Tierra Energy opened its first field office in the city of Salvador to manage operations on our four blocks in the Recôncavo Basin. In 2011, we also received approval from the ANP for these blocks and Gran Tierra Energy saw its first production from the Recôncavo Basin. The production from one of our four blocks averaged 118 BOEPD. We anticipate two additional wells will be on production before mid 2012.



"We have established an asset base with significant exploration potential in a number of blocks, covering two basins: onshore Recôncavo and offshore Camamu-Almada. Gran Tierra Energy Brazil intends to deploy modern North American horizontal drilling techniques as part of our 2012 drilling program that should allow us to further unlock the value of our blocks."

Júlio César Moreira, President
Gran Tierra Energy Brazil

PROVED RESERVES (NAR)

0.4 MMBBL

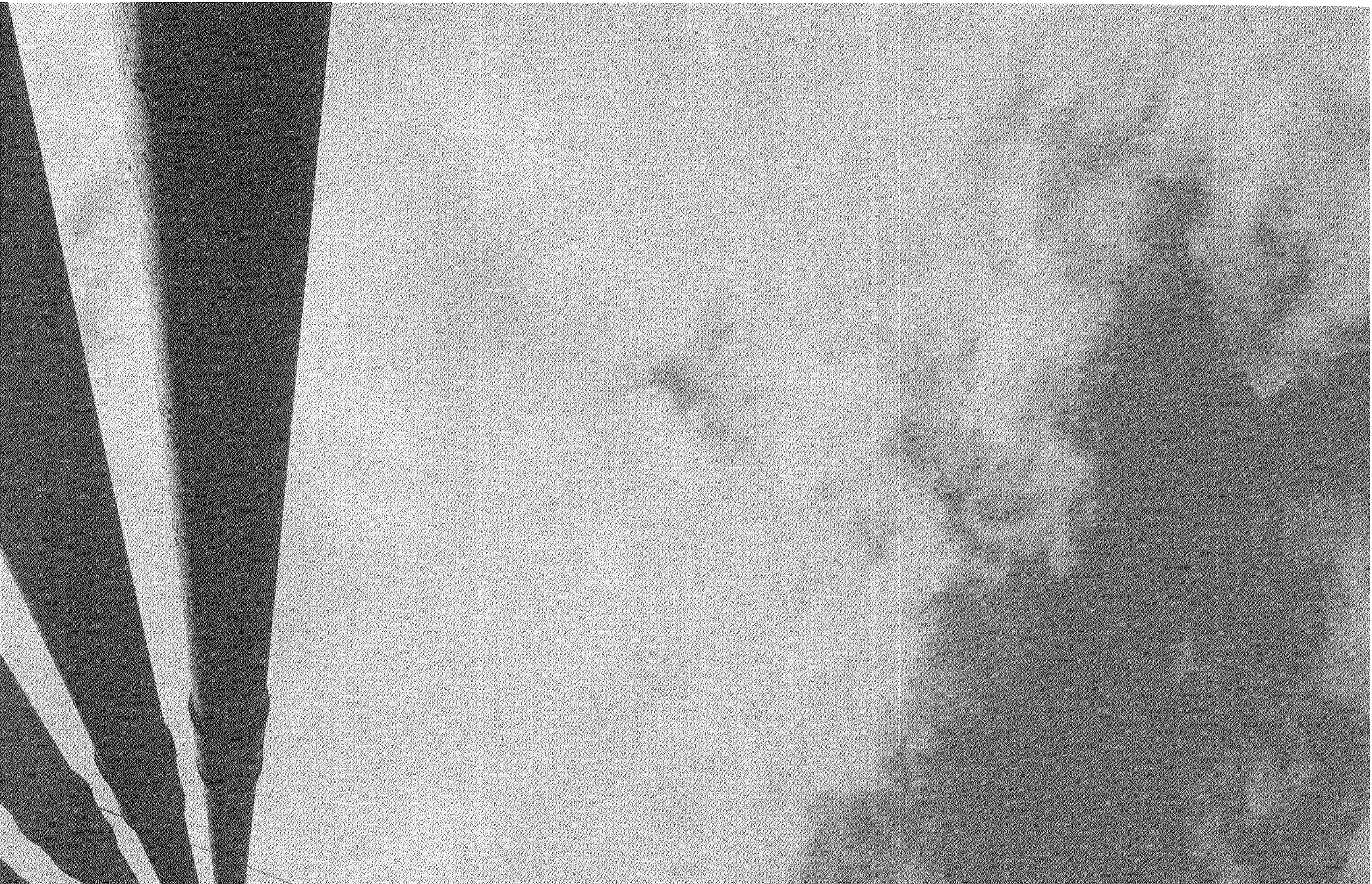
PROVED + PROBABLE (NAR)

1.5 MMBBL

PROVED + PROBABLE + POSSIBLE (NAR)

3.6 MMBBL


we will...



Continue initiatives to grow land, reserves, and production

Plan to build and consolidate regional positions, leverage and expand strategic relationships

Strive to add substantial value through our aggressive drilling program

Peru

"We have assembled a large land position in Peru, and continue to build an important portfolio of exploration opportunities to determine key targets for our drilling program in 2012 and beyond. Gran Tierra Energy Peru has a number of exploration targets with significant resource potential."

Carlos Monges , President
Gran Tierra Energy Peru

GROSS BLOCKS	2012 GROSS EXPLORATION WELL	GROSS ACRES	NET ACRES
5	1	6.4 MM	3.1 MM

Peru provides Gran Tierra Energy with high impact frontier exploration drilling. In March 2011, we acquired Petrolifera which added two blocks in the Ucayali Basin in Peru, Block 107 and Block 133, which substantially increased our land position. An oil field has already been discovered on Block 95, with the discovery well drilled in 1974 flowing 807 BOPD naturally without pumps. The Peru capital budget for 2012 is $78 million and is expected to include drilling of one gross exploration well.

In 2012, we plan to drill one exploration well in the second half on Block 95 of the Marañon Basin. Drilling costs are anticipated to be $47 million, and $31 million is budgeted for seismic acquisition and facility costs. Seismic acquisition and processing is planned to continue in 2012 in Blocks 123 and 129, with a 563 km 2D infill seismic program expected to be acquired in the first half of 2012. On Block 107 of the Ucayali Basin, a 390 km infill 2D seismic program is planned for the second half of 2012 in preparation for additional oil exploration drilling in 2013.

EXPLORATION

Argentina

The Argentina capital budget for 2012 is $47 million and is expected to include drilling of three gross exploration wells and nine gross development wells.

GROSS BLOCKS

12

2012 GROSS EXPLORATION WELLS

3

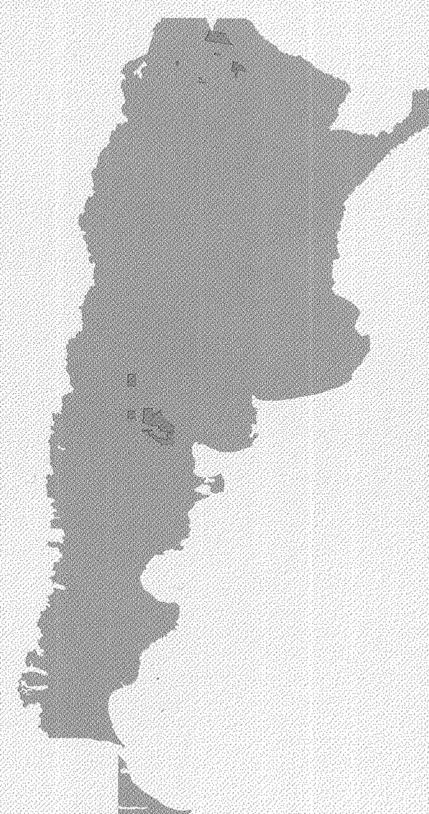
GROSS ACRES

1.4 MM

NET ACRES

0.8 MM

Gran Tierra Energy's planned work program for Argentina in 2012 includes drilling three gross exploration wells, 9 gross development wells and 9 workovers on existing wells. The company has allocated $33 million to drilling, $7 million to facilities and pipelines, and $7 million to G&G expenditures. Seven gross development wells are planned for the Puesto Morales Field, one on the Surubi Block and one on the Rinconada Sur Block, for the purposes of improving recovery in the remaining reserves, minimizing water channeling, and subsequently growing production from these assets. Gran Tierra Energy plans to drill two oil exploration wells on the Rinconada Sur Block, as well an exploration well on the Puesto Guevara Block.



PRODUCTION

Argentina

GROSS PRODUCING WELLS

122

INCREASE IN DAILY AVERAGE PRODUCTION

↑223%

2011 PRODUCTION

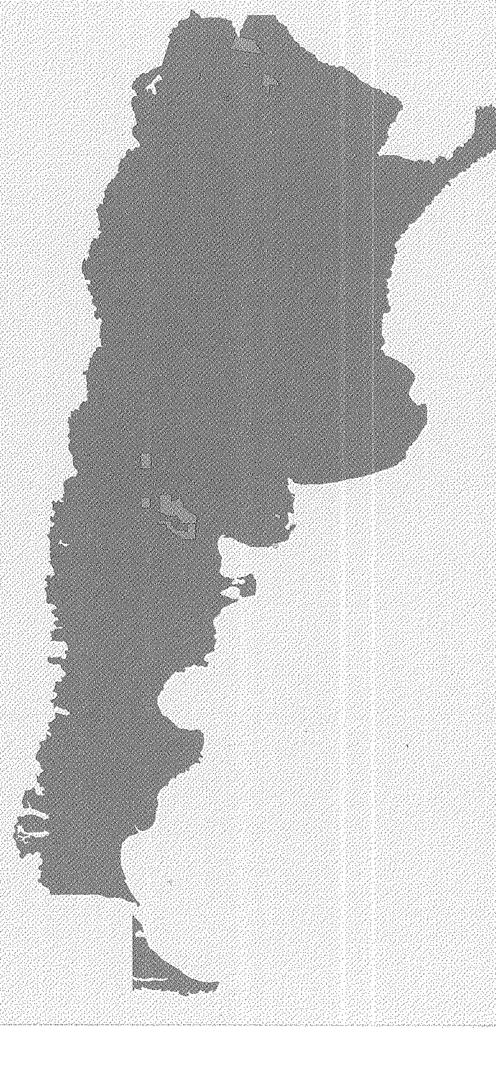
2,513

BOEPD NAR

In 2011, Gran Tierra Energy added to the Argentina portfolio with the acquisition of Petrolifera and their 220,000 net acres in seven blocks in the Neuquen Basin: Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Vaca Mahuida, and Puesto Guevara. The Gobernador Ayala II Block was also acquired from Petrolifera and relinquished in 2011. This acquisition resulted in a 35% increase to our land position and a 233% increase to our production by the end of the year. Contributing to the success in Argentina, Gran Tierra Energy made an oil discovery on the Rinconada Norte Block with the RN x-1004 exploration well and stabilized gas production from the Puesto Morales Block. This discovery is expected to add to our existing oil production in eight other blocks.

"We successfully managed to mitigate declines on assets acquired through Petrolifera Petroleum through a number of successful workovers. Gran Tierra Energy Argentina has a robust program planned for 2012 that includes drilling exploration and development wells combined with workovers and infrastructure improvements, all geared towards further production growth."

Rafael Orunesu, President
Gran Tierra Energy Argentina



PROVED RESERVES (NAR)

5.8 MMBOE

PROVED + PROBABLE (NAR)

9.9 MMBOE

PROVED + PROBABLE + POSSIBLE (NAR)

23.1 MMBOE

Letter to Shareholders

Since its inception in 2005, Gran Tierra Energy has generated steady year-over-year operational and financial growth, and this trend continued in 2011. During the year we retained our focus on growing our businesses in Colombia, Argentina, Peru and Brazil. We added new exploration acreage and drilling prospects to the portfolio in all four countries, and established partnerships with strategic players in the region.

Operationally, we attained record levels of production and reserves through a combination of superior reservoir management of existing reserves, appraisal success of recent exploration discoveries, the making of a new oil discovery, and the acquisition of Petrolifera. Financially, our revenue, net income and funds flow from operations reached record levels through a combination of record levels of production and strong oil prices.

In Colombia, the completion of the Moqueta to Costayaco flow-line and initiation of production from the Moqueta field was a major achievement. This is the first time that an oil field in Colombia has been discovered and put into production with operations entirely supported by helicopter and without access by road, minimizing the environmental footprint of Gran Tierra Energy's operations at this early stage of development. In addition, the company announced the successful Melero-1 oil exploration well on the Garibay Block in the Llanos basin with our partner CEPSA Colombia S.A. We expanded our successful relationship with CEPSA during the year through an acreage exchange that further expanded Gran Tierra Energy's position in the Llanos Basin with the Llanos-22 Block, subject to ANH approval. Subsequent to year-end 2011, we announced another oil discovery, Ramiriqui-1, on this new acreage.

In Brazil, Gran Tierra Energy initiated its drilling program on the onshore Recôncavo and offshore Camamu-Almada Basins, where we have assembled large acreage positions and a diverse exploration and development drilling portfolio. Work progressed in 2011 and continues in 2012 on developing a recent oil discovery and testing an exciting resource play concept where Gran Tierra Energy is deploying modern North American horizontal drilling technology in order to further unlock the potential of an already resource rich country.

In Peru, Gran Tierra Energy advanced plans to drill an oil exploration well in Block 95 and we continue to mature opportunities on our expansive land position for drilling in 2013 and beyond. With 100% working interest in two blocks in the Ucayalli Basin on trend with the world class Camisea discovery, and a joint venture partnership with global operators in the Marañon Basin, the company is positioned to explore the material prospective resource potential of those lands.

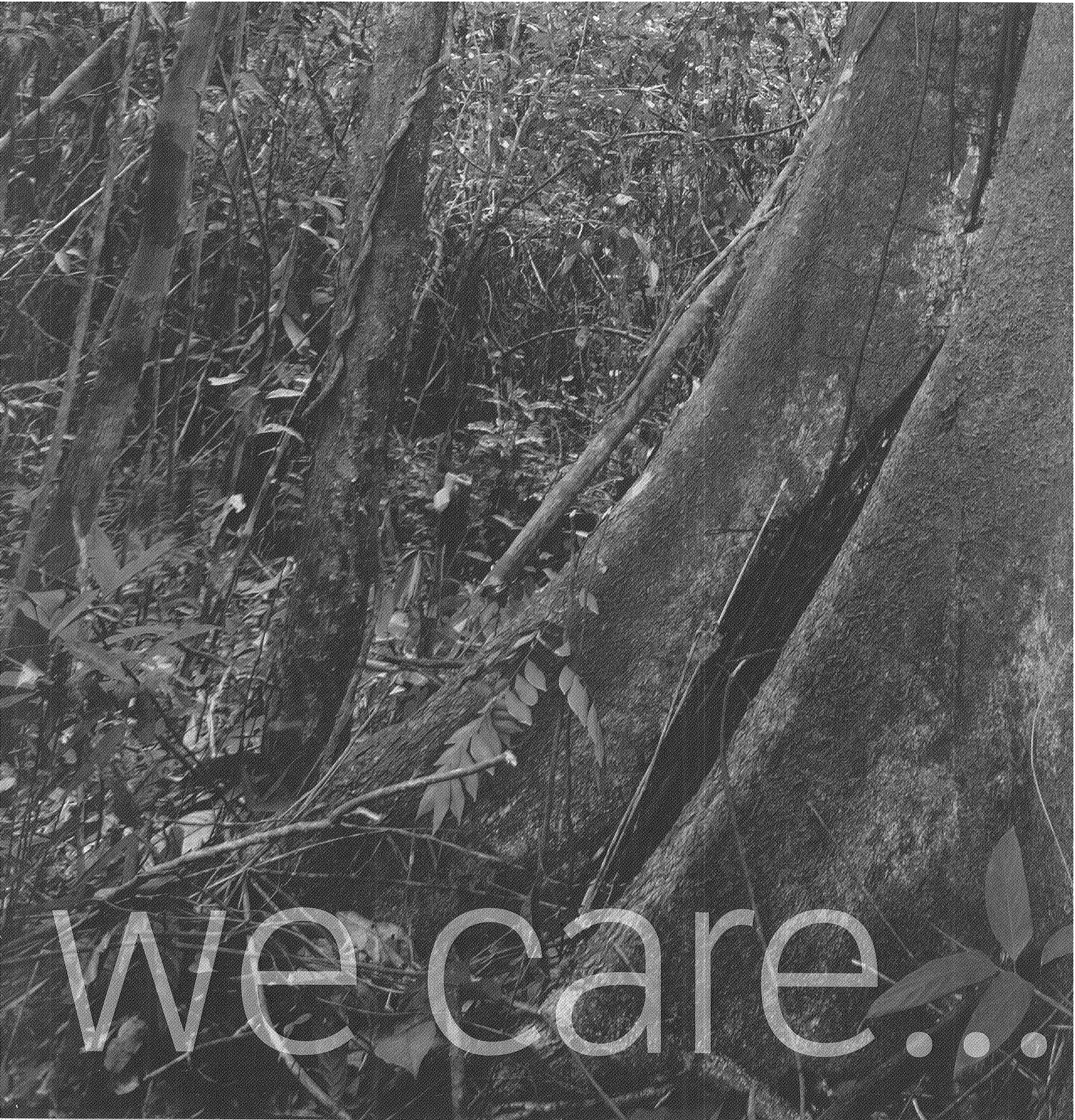
In Argentina, work was conducted in 2011 on the newly acquired Petrolifera properties in the Neuquen Basin where we successfully halted the production declines experienced on those properties in recent years through a number of successful workovers. We expect work will continue through 2012 to begin growing production. Our effort has been rewarded by a very successful appraisal well in the Noroeste Basin, Proa-2, which tested a record 6,300 barrels of oil per day gross.

One of the foundations for success at Gran Tierra Energy has been an active commitment to building strong relationships with communities in the regions where we operate. We continue to ensure open and transparent consultations prior to, during, and after operational activities, and support local citizens with a focus on education, medical and infrastructure initiatives. This enables communities and other stakeholders to share in the successful growth of Gran Tierra Energy.

Our $444 million 2012 capital program continues to focus on growing reserves and production through exploration and development activities in Colombia, Argentina, Peru and Brazil. Our excellent results in 2011 have allowed us to enter 2012 with another year of robust growth activities fully funded from cash flow and cash on hand at current commodity prices and production levels, positioning Gran Tierra Energy for continued growth in the years to come.

Sincerely,

Dana Coffield
President and Chief Executive Officer


we care...


Integrity
Commitment
Responsibility

Continuing Our Commitment

We selected "Gran Tierra" ("Great Earth") as our Company name to reflect our respect for both the communities we interact with and the environment in which we operate. Gran Tierra Energy aims to build and maintain relationships that result in long-term benefits for all stakeholders, including local communities.

Gran Tierra Energy regularly interacts with local communities, as well as government and non-government agencies, to ensure we continue to operate in a sustainable manner. In 2012, we plan to more than double our financial commitments in the regions in which we operate, to provide support for projects aiming to improve infrastructure, education, sustainability and social welfare.

Our business activities are conducted according to rigorous ethical, professional and legal standards. Our Company's Code of Business Conduct and Ethics requires:

- Commitments and expectations to ensure we maintain the highest standards of business conduct and ethics
- Business practices and principles of behavior that support this commitment
- Development of organizational values, policies, and expected behaviors
- Compliance requirements for all employees, officers,.directors and contractors
- Compliance with auditing and monitoring systems

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Cautionary Information Regarding Forward-Looking Statements

This Annual Report contains certain forward-looking information, forward-looking statements and forward-looking financial outlook (collectively, "forward-looking statements") under the meaning of applicable securities laws, including Canadian Securities Administrators' National Instrument 51-102 – Continuous Disclosure Obligations, the United States Securities Act of 1933 and the Unites States Securities and Exchange Act of 1934. The use of the words "believe", "goal", "expect", "project", "plan", "outlook", "anticipate", "schedule", "intend", "will", "target," "could," derivations of these words and similar expressions are intended to identify forward-looking statements. All statements other than statements of historical facts included in this Annual Report are forward-looking statements including, without limitation, statements regarding: Gran Tierra Energy's financial position; estimated quantities and net present values of reserves; business strategy; plans and objectives of management for future operations; covenant compliance; Gran Tierra Energy's planned capital expenditure program and work program for 2012 including the allocation of budgeted amounts and planned operations and expenditures, including exploration and evaluation activities, drilling, testing, seismic programs and seismic acquisition and processing, facilities work and geological and geophysical work, in Colombia, Peru, Brazil and Argentina; Gran Tierra Energy's expectation that it will fund its 2012 capital program through cash flow from operations and cash on hand; Gran Tierra Energy's expectation that it will retain financial flexibility with a strong cash position and no debt so that it can be positioned to undertake further development opportunities and pursue value-add acquisitions; Gran Tierra Energy's long-term growth and financing strategy; the timing and outcome of planned operations and expenditures; intended drilling, drilling techniques, workovers and infrastructure improvements and the potential impact of such activities including expectations respecting improved recoveries, minimization of water channelling and production growth; Gran Tierra Energy's plans to build and consolidate regional positions, leverage and expand strategic relationships and continue initiatives to grow land, reserves and production; expectations respecting growth and the addition of substantial value; expectations respecting Gran Tierra Energy's infrastructure initiatives and consultations with communities and other stakeholders and the benefits expected to be derived therefrom; together with all other statements regarding expected or planned development, testing, drilling, production, expenditures or exploration, or that otherwise reflect expected future results or events.

The forward-looking statements contained in this Annual Report reflect several material factors and expectations and assumptions of Gran Tierra Energy including, without limitation, assumptions relating: estimated costs of potential exploration, evaluation, construction and development activities; future crude oil and natural gas prices; assumptions relating to log evaluations; Gran Tierra Energy's geological and engineering estimates; projected production; the accuracy of reserves estimates; that Gran Tierra Energy will continue to conduct its operations in a manner consistent with past operations; the accuracy of testing and production results and seismic data; rig availability; the effects of horizontal and other drilling techniques; and the general continuance of current or, where applicable, assumed operational, regulatory and industry conditions. Gran Tierra Energy believes the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking statements contained in this Annual Report may not be appropriate for other purposes and are subject to risks, uncertainties and other factors that could cause actual results or outcomes to differ materially from those contemplated by the forward-looking statements, including, among others: Gran Tierra Energy's operations are located in South America, and unexpected problems can arise due to guerrilla activity, technical difficulties and operational difficulties which may impact its testing and drilling operations, and the production, transportation or sale of its products; geographic, political, regulatory and weather conditions can impact testing and drilling operations and the production, transportation or sale of its products; permits and approvals from regulatory and governmental authorities may not be received in the manner or on the timelines expected or at all; uncertainties of estimates with respect to reserves and resources; imprecision in estimating capital expenditures and operating expenses; imprecision in estimates of future production capacity; uncertainties associated with geological interpretations; imprecision in estimating the timing, costs and levels of production and drilling; and the risk that current global economic and credit market conditions may impact oil prices and oil consumption more than Gran Tierra Energy currently predicts, which could require Gran Tierra Energy to modify its exploration, drilling and/or construction activities. Although the current capital program of Gran Tierra Energy is based upon the current expectations of the management of Gran Tierra Energy, there may be circumstances in which, for unforeseen reasons, a reallocation of funds may be necessary as may be determined at the discretion of Gran Tierra Energy and there can be no assurance as at the date of this Annual Report as to how those funds may be reallocated. Should any one of a number of issues arise, Gran Tierra Energy may find it necessary *to alter its current business strategy and/or capital spending program. Accordingly, readers should not place undue reliance on the forward-looking statements contained herein. Further information on potential factors that could affect Gran Tierra Energy are included in risks detailed in this Annual Report and as more fully discussed in Part I, Item 1A "Risk Factors" in Gran Tierra Energy's Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012. The Annual Report on Form 10-K is available on a Web site maintained by the Securities and Exchange Commission at http://www.sec.gov and on SEDAR at www.sedar.com. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Report are made as of the date of this Annual Report (other than information that speaks as of an earlier date) and Gran Tierra Energy disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as expressly required by applicable securities legislation.*

Glossary Of Oil and Gas Terms

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	BOPD	barrels of oil per day
Mbbl	thousand barrels	Mcf	thousand cubic feet
MMbbl	million barrels	MMcf	million cubic feet
BOE	barrels of oil equivalent	Bcf	billion cubic feet
MMBOE	million barrels of oil equivalent	NGL	natural gas liquids
BOEPD	barrels of oil equivalent per day	NAR	net after royalty

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

In the discussion that follows we discuss our interests in wells and/or acres in gross and net terms. Gross oil and natural gas wells or acres refer to the total number of wells or acres in which we own a working interest. Net oil and natural gas wells or acres are determined by multiplying gross wells or acres by the working interest that we own in such wells or acres. Working interest refers to the interest we own in a property, which entitles us to receive a specified percentage of the proceeds of the sale of oil and natural gas, and also requires us to bear a specified percentage of the cost to explore for, develop and produce that oil and natural gas. A working interest owner that owns a portion of the working interest may participate either as operator, or by voting its percentage interest to approve or disapprove the appointment of an operator, in drilling and other major activities in connection with the development of a property.

We also refer to royalties and farm-in or farm-out transactions. Royalties are paid to governments on the production of oil and gas, either in kind or in cash. Royalties also include overriding royalties paid to third parties. Our reserves, production volumes and sales are reported net after deduction of royalties. Production volumes are also reported net of inventory adjustments. Farm-in or farm-out transactions refer to transactions in which a portion of a working interest is sold by an owner of an oil and gas property. The transaction is labeled a farm-in by the purchaser of the working interest and a farm-out by the seller of the working interest. Payment in a farm-in or farm-out transaction can be in cash or in kind by committing to perform and/or pay for certain work obligations.

In the petroleum industry, geologic settings with proven petroleum source rocks, migration pathways, reservoir rocks and traps are referred to as petroleum systems.

Several items that relate to oil and gas operations, including aeromagnetic and aerogravity surveys, seismic operations and several kinds of drilling and other well operations, are also discussed in this document.

Aeromagnetic and aerogravity surveys are a remote sensing process by which data is gathered about the subsurface of the earth. An airplane is equipped with extremely sensitive instruments that measure changes in the earth's gravitational and magnetic field. Variations as small as 1/1,000th in the gravitational and magnetic field strength and direction can indicate structural changes below the ground surface. These structural changes may influence the trapping of hydrocarbons. These surveys are an inexpensive way of gathering data over large regions.

Seismic data is used by oil and natural gas companies as their principal source of information to locate oil and natural gas deposits, both for exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computer software applications are then used to process the raw data to develop an image of underground formations. 2-D Seismic is the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several square miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Wells drilled are classified as exploration, development or stratigraphic. An exploration well is a well drilled in search of a previously undiscovered hydrocarbon-bearing reservoir. A development well is a well drilled to develop a hydrocarbon-bearing reservoir that is already discovered. Exploration and development wells are tested during and after the drilling process to determine if they have oil or natural gas that can be produced economically in commercial quantities. If they do, the well will be completed for production, which could involve a variety of equipment, the specifics of which depend on a number of technical geological and engineering considerations. If there is no oil or natural gas (a "dry" well), or there is oil and natural gas but the quantities are too small and/or too difficult to produce, the well will be abandoned. Abandonment is a completion operation that involves closing or "plugging" the well and remediating the drilling site. An injector well is a development well that will be used to inject fluid into a reservoir to increase production from other wells. A stratigraphic well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if drilled in an unknown area or "development type" if drilled in a known area.

Risks Related to Our Business

- Our Lack of Diversification Will Increase the Risk of an Investment in Our Common Stock.
- We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses.
- Guerrilla Activity in Colombia Could Disrupt or Delay Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Colombia.
- Our Business May Suffer If We Do Not Attract and Retain Talented Personnel.
- Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results.
- Our Business is Subject to Local Legal, Political and Economic Factors Which are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably.
- We Have an Aggressive Business Plan, and if we do not Have the Resources to Execute on our Business Plan, We May Be Required to Curtail Our Operations.
- Strategic and Business Relationships upon Which We May Rely are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.
- Disputes or Uncertainties May Arise in Relation to our Royalty Obligations.
- Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.
- Exchange Controls and New Taxes Could Materially Affect our Ability to Fund Our Operations and Realize Profits from Our Foreign Operations.
- Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business.
- Maintaining Good Community Relationships and Being a Good Corporate Citizen may be Costly and Difficult to Manage.

- Our Operations Involve Substantial Costs and are Subject to Certain Risks Because the Oil and Gas Industries in the Countries in Which We Operate are Less Developed.
- Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations.
- Negative Political Developments in Peru May Negatively Affect our Proposed Operations.
- The United States Government May Impose Economic or Trade Sanctions on Colombia That Could Result In A Significant Loss To Us.
- We May Be Unable to Obtain Additional Capital That We Will Require to Implement Our Business Plan, Which Could Restrict Our Ability to Grow.
- We May Not Be Able To Effectively Manage Our Growth, Which May Harm Our Profitability.

Risks Related to Our Industry

- Unless We are Able to Replace Our Reserves, and Develop and Manage Oil and Gas Reserves and Production on an Economically Viable Basis, Our Reserves, Production and Cash Flows May Decline as a Result.
- We are Required to Obtain Licenses and Permits to Conduct Our Business and Failure to Obtain These Licenses Could Cause Significant Delays and Expenses That Could Materially Impact Our Business.
- Our Exploration for Oil and Natural Gas Is Risky and May Not Be Commercially Successful, Impairing Our Ability to Generate Revenues from Our Operations.
- Estimates of Oil and Natural Gas Reserves that We Make May Be Inaccurate and Our Actual Revenues May Be Lower and Our Operating Expenses may be Higher than Our Financial Projections.
- If Oil and Natural Gas Prices Decrease, We May be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.
- Drilling New Wells and Producing Oil and Natural Gas from Existing Facilities Could Result in New Liabilities, Which Could Endanger Our Interests in Our Properties and Assets.
- Our Inability to Obtain Necessary Facilities and/or Equipment Could Hamper Our Operations.
- Decommissioning Costs Are Unknown and May be Substantial; Unplanned Costs Could Divert Resources from Other Projects.
- Prices and Markets for Oil and Natural Gas Are Unpredictable and Tend to Fluctuate Significantly, Which Could Reduce Our Profitability, Growth and Value.
- Penalties We May Incur Could Impair Our Business.
- Policies, Procedures and Systems to Safeguard Employee Health, Safety and Security May Not be Adequate.
- Environmental Risks May Adversely Affect Our Business.
- Our Insurance May Be Inadequate to Cover Liabilities We May Incur.
- Challenges to Our Properties May Impact Our Financial Condition.
- We Will Rely on Technology to Conduct Our Business and Our Technology Could Become Ineffective Or Obsolete.

Risks Related to Our Common Stock

- The Market Price of Our Common Stock May Be Highly Volatile and Subject to Wide Fluctuations.
- We Do Not Expect to Pay Dividends In the Foreseeable Future.

Selected Financial Data

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Statement of Operations Data					
Revenues and other income					
Oil and natural gas sales	$ 596,191	$ 373,286	$ 262,629	$ 112,805	$ 31,853
Interest income	1,216	1,174	1,087	1,224	425
Total revenues and other income	597,407	374,460	263,716	114,029	32,278
Expenses					
Operating	86,497	59,446	40,784	19,218	10,474
DD&A expenses	231,235	163,573	135,863	25,737	9,415
G&A Expenses	60,389	40,241	28,787	18,593	10,232
Liquidated damages	–	–	–	–	7,367
Equity tax	8,271	–	–	–	–
Financial instruments (gain) loss	(1,522)	(44)	190	(193)	3,040
Gain on acquisition	(21,699)	–	–	–	–
Foreign exchange (gain) loss	(11)	16,838	19,797	6,235	(78)
Total expenses	363,160	280,054	225,421	69,590	40,450
Income (loss) before income taxes	234,247	94,406	38,295	44,439	(8,172)
Income tax expense	(107,330)	(57,234)	(24,354)	(20,944)	(295)
Net income (loss)	$ 126,917	$ 37,172	$ 13,941	$ 23,495	$ (8,467)
Net income (loss) per common share—basic	$ 0.46	$ 0.15	$ 0.06	$ 0.19	$ (0.09)
Net income (loss) per common share—diluted	$ 0.45	$ 0.14	$ 0.05	$ 0.16	$ (0.09)

Balance Sheet Data	As at December 31, 2011	As at December 31, 2010	As at December 31, 2009	As at December 31, 2008	As at December 31, 2007
Cash and cash equivalents	$ 351,685	$ 355,428	$ 270,786	$ 176,754	$ 18,189
Working capital (including cash)	213,100	265,835	215,161	132,807	8,058
Oil and gas properties	1,036,850	721,157	709,568	765,050	63,202
Deferred tax asset—long term	4,747	-	7,218	10,131	1,839
Total assets	1,626,780	1,249,254	1,143,808	1,072,625	112,797
Deferred tax liability—long term	186,799	204,570	216,625	213,093	9,235
Total long-term liabilities	207,633	210,075	221,786	218,461	12,553
Shareholders' equity	$ 1,174,318	$ 886,866	$ 816,426	$ 791,926	$ 76,792

In November 2008, we acquired Solana Resources Limited ("Solana") for $671.8 million through the issuance to Solana stockholders of either shares of our common stock or shares of common stock of a subsidiary of Gran Tierra. On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited ("Petrolifera") pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. See "Business Combination" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further details.

Preliminary Note to Management's Discussion and Analysis of Financial Condition and Results of Operations

The following Management's Discussion and Analysis of Financial Condition and Results of Operations is as it appears in our Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 27, 2012, other than the italicized cautionary language at the beginning of the section.

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

This report, and in particular this Management's Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language in the section entitled "Cautionary Information Regarding Forward Looking Statements" earlier in this Annual Report regarding the identification and risks relating to forward looking statements.

The following discussion of our financial condition and results of operations should be read in conjunction with the Financial Statements and Supplementary Data included in this Annual Report.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Argentina, Peru, and Brazil, and we are headquartered in Calgary, Alberta, Canada. Our reportable segments are Colombia, Argentina and Peru. Brazil is not a reportable segment because the level of activity in Brazil is not significant at this time. For the year ended December 31, 2011, Colombia generated 91% (2010—96%; 2009—95%) of our revenue and other income.

As of December 31, 2011, we had estimated proved reserves NAR of 34.0 MMBOE, comprising 91% oil and 9% natural gas, of which 76% were proved developed reserves. Our primary source of liquidity is cash generated from our operations.

On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited ("Petrolifera") pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru.

On June 15, 2011, we completed the acquisition of a 70% participating interest in four blocks in Brazil. The agreement had an effective date of September 1, 2010. Purchase consideration totalled $40.1 million. With the exception of one block which has a producing well, the remaining blocks are unproved properties.

In September 2011, we announced two farm-in agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with PetróleoBrasileiro S.A. ("Petrobras"), in Brazil's deepwater offshore Camamu-Almada Basin, subject to obtaining regulatory approval from Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP"). ANP approval for the Block BM-CAL-7 farmout agreement was received in first quarter of 2012. The ANP has announced the 1-STAT-7-BAS exploration well has been completed after reaching a total measured depth of 3,651 meters. Contractually, Gran Tierra is restricted from discussing well results. In accordance with the terms of the farmout agreement, we gave notice to Statoil that we will not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result the farmout agreement for BM-CAL-10 has been terminated and we will not receive any interest in BM-CAL-10.

Inflation has not had a material impact on our results of operations in the three years ended December 31, 2011 and is not expected to have a material impact on our results of operations in the future.

The price of oil is a critical factor to our business and the price of oil has historically been volatile. Volatility could be detrimental to our financial performance. During 2011, the average price realized for our oil was $96.60 per barrel (2010—$71.19; 2009—$56.79).

Business Strategy

Our plan is to continue to build an international oil and gas company through acquisition and exploitation of under-developed prospective oil and gas assets, and to develop these assets with exploration and development drilling to grow commercial reserves and production. Our initial focus is in select countries in South America, currently Colombia, Argentina, Peru, and Brazil; we will consider other regions for future growth should those regions make strategic and commercial sense in creating additional value.

We have applied a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving additional reserve and production growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with proven petroleum systems; attractive royalty, taxation and other fiscal terms; and stable legal systems.

Highlights

							Year Ended December 31,
	2011	% Change		2010	% Change		2009
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE)[1]	34.0	43		23.8	6		22.4
Production (BOEPD)[1][2]	17,408	20		14,448	14		12,684
Prices Realized—per BOE	$ 93.83	33	$	70.79	25	$	56.73
Revenue and Other Income ($000s)	$ 597,407	60	$	374,460	42	$	263,716
Net Income ($000s)	$ 126,917	241	$	37,172	167	$	13,941
Net Income Per Share—Basic	$ 0.46	207	$	0.15	150	$	0.06
Net Income Per Share—Diluted	$ 0.45	221	$	0.14	180	$	0.05
Funds Flow From Operations ($000s)[3]	$ 319,046	57	$	203,136	27	$	159,479
Capital Expenditures ($000s)	$ 327,647	85	$	177,039	101	$	88,124

							As at December 31,
	2011	% Change		2010	% Change		2009
Cash & Cash Equivalents ($000s)	$ 351,685	(1)	$	355,428	31	$	270,786
Working Capital (including cash & cash equivalents) ($000s)	$ 213,100	(20)	$	265,835	24	$	215,161
Property, Plant and Equipment ($000s)	$ 1,044,842	44	$	727,024	2	$	712,743

(1) Gas volumes are converted to BOE at the rate of six Mcf of gas per barrel of oil, based on the approximate relative energy content of gas and oil. The conversion ratio does not assume price equivalency and the price for a barrel of oil equivalent for natural gas may differ significantly from the price of a barrel of oil.

(2) Production represents production volumes NAR adjusted for inventory changes.

(3) Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under generally accepted accounting principles in the United States of America ("GAAP"). Management uses this financial measure to analyze operating performance and the income generated by our principal business activities prior to the consideration of how non-cash items affect that income, and believes that this financial measure is also useful supplemental information for investors to analyze operating performance and our financial results. Investors should be cautioned that this measure should not be construed as an alternative to net income or other measures of financial performance as determined in accordance with GAAP. Our method of calculating this measure may differ from other companies and, accordingly, it may not be comparable to similar measures used by other companies. Funds flow from operations, as presented, is net income adjusted for depletion, depreciation, accretion and impairment ("DD&A"), deferred taxes, stock-based compensation, (gain) loss on financial instruments, unrealized foreign exchange (gain) loss, settlement of asset retirement obligation, equity tax and gain on acquisition. A reconciliation from funds flow from operations to net income is as follows:

			Year Ended December 31,
	2011	2010	2009
Funds Flow From Operations—Non-GAAP Measure ($000s)			
Net income	$ 126,917	$ 37,172	$ 13,941
Adjustments to reconcile net income to funds flow from operations			
DD&A expenses	231,235	163,573	135,863
Deferred taxes	(29,222)	(20,090)	(15,355)
Stock-based compensation	12,767	8,025	5,309
(Gain) loss on financial instruments	(1,354)	(44)	277
Unrealized foreign exchange (gain) loss	(1,695)	14,786	19,496
Settlement of asset retirement obligation	(345)	(286)	(52)
Equity tax	2,442	-	-
Gain on acquisition	(21,699)	-	-
Funds flows from operations	$ 319,046	$ 203,136	$ 159,479

Operational Highlights for the Year Ended December 31, 2011

- In 2011, oil and natural gas production, NAR and inventory adjustments, averaged 17,408 BOEPD, an increase of 20% over 2010. The increase was due to improved production from the Moqueta, Jilguero and Juanambu fields, production from Petrolifera and the reduced impact of pipeline interruptions. Production NAR from Petrolifera's properties during 2011 was 1,811 BOEPD.
- Estimated proved oil and NGL reserves, NAR, as of December 31, 2011, were 30.9 MMbbl, a 31% increase from the estimated proved reserves as at December 31, 2010. The increase was due primarily to positive technical revisions to Costayaco reserves (based on reservoir performance), the drilling of additional appraisal wells in the Moqueta field, the inclusion of proved reserves associated with the Petrolifera acquisition and the 70% working interest in Block 155 acquired in Brazil, which more than offset 2011 oil production. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2011 were 10.5 MMbbl and 17.6 MMbbl, respectively.
- Estimated proved gas reserves, NAR, as of December 31, 2011, were 18.3 Bcf compared with 1.2 Bcf as at December 31, 2010. The increase was due to the acquisition of Petrolifera. At December 31, 2011, 75% of proved gas reserves were in the Sierra Nevada Block and 19% were in the Puesto Morales Blocks, both of which were acquired in the Petrolifera acquisition. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Colombia

- In the Moqueta field in the Chaza Block, the Moqueta -4 delineation well was successfully completed and confirmed additional oil bearing reservoirs. We completed two additional development wells in the Moqueta field: Moqueta -5 and Moqueta -6. Construction of the Moqueta-to-Costayaco pipeline was completed with transportation of first oil production from Moqueta commencing in June of 2011. A parallel four-inch gas line was completed that will be used to transport gas from Costayaco to Moqueta for anticipated gas injection for pressure support.
- In the Costayaco field, we completed three development wells.
- In the Guayuyaco and Garibay Blocks, the Juanambu -3 and Jilguero -2 development wells were completed as producing wells and the Melero -1 exploration well was completed and resulted in an oil discovery.
- We entered into a farmout agreement with CEPSA Colombia S.A. ("CEPSAC"), a wholly-owned subsidiary of Compañia Española de Petróleos S.A. We will earn a 45% non-operated working interest in the Llanos-22 Block (CEPSAC will retain 55% and operatorship) and CEPSAC will farm-in for a 30% working interest on the Piedemonte Norte Block. Under the terms of the farm-in agreements, in addition to the swap of the 30% working interest in Piedemonte Norte block, we will pay $1.5 million towards historical costs and a partial carry on the current well being drilled. The completion of the transfer is subject to approval by Colombia's Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH"). Our partner began drilling the Ramiriqui-1 oil exploration well in the fourth quarter of 2011.
- We drilled exploration wells on the Chaza Block, the Magdalena Block, the Piedemonte Sur Block and the Rumiyaco Block all of which were plugged and abandoned.

Argentina

- We completed drilling the first of four new development wells in the Puesto Morales Block, with the purpose of improving recovery and growing production from this mature oil field. We completed workovers on 18 wells, with successful results. We also drilled and completed two producing development wells on the Puesto Morales Este Block.
- Our partner drilled four exploration wells in the Rinconada Norte Block which resulted in new discoveries of oil, one of which tested 1,023 BOE gross per day. A wholly-owned subsidiary of America Petrogas Inc. is the operator of the Rinconada Norte Block with a 65% working interest, while we hold a 35% non-operated working interest.
- We successfully farmed out a 50% interest in the Santa Victoria Block in the Noroeste Basin of northwestern Argentina to Apache Corporation ("Apache") in March 2011.

Peru

- In January 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block to us. A drilling location has been identified for the first exploration well on Block 95, with civil construction initiated in the third quarter of 2011.
- In September 2010, we acquired a 20% non-operated working interest in ConocoPhillips operated Block 123, Block 124 and Block 129, subject to government approval. The approval for these blocks was granted in March 2011 with final assignment completed in April 2011. We subsequently relinquished our interest in Block 124.
- We drilled the Kanatari -1 exploration well on Block 128 which was plugged and abandoned and subsequently relinquished our interest in Blocks 122 and 128.

Brazil

- On June 15, 2011, we received final approvals for the acquisition of a 70% participating interest in Blocks 129, 142, 155 and 224 in the onshore Recôncavo Basin of Brazil and also became the operator of these fields effective from that date.
- We drilled two gross exploration wells on Block 142 and Block 129 and spud a delineation well on Block 155.
- We announced two farm-in agreements with Statoil in a joint venture with Petrobras, in Brazil's deepwater offshore Camamu-Almada Basin. The ANP has announced the 1-STAT-7-BAS exploration well has been completed after reaching a total measured depth of 3,651 meters. Contractually, we are restricted from discussing well results. In accordance with the terms of the farmout agreement, we gave notice to Statoil that we will not enter into and assume our share of the work obligations of the second exploration period on one of the two blocks and as a result the farmout agreement for this block was terminated. ANP approval was received for the second block in the first quarter of 2012.

Financial Highlights for the Year Ended December 31, 2011

- Revenue and other income increased by 60% to $597.4 million in 2011 compared with $374.5 million in 2010 due to increased production and higher oil prices. Average prices realized per BOE in 2011 were $93.83, an increase of 33% compared with $70.79 in 2010.
- Net income grew by 241% from the prior year to $126.9 million, representing basic net income per share of $0.46 and diluted net income per share of $0.45. This compares with net income of $37.2 million, or $0.15 per share basic and $0.14 per share diluted, in 2010. The increase in net income was the result of increased oil and natural gas sales, a $21.7 million gain on the Petrolifera acquisition and the absence of foreign exchange losses, partially offset by a $42.0 million impairment loss in the Peru cost center, a $25.7 million impairment loss in the Argentina cost center, a Colombian equity tax of $8.3 million and increased operating, DD&A and general and administrative ("G&A") expenses. The equity tax is assessed every four years.
- Funds flow from operations increased 57% to $319.0 million in 2011 from $203.1 million in 2010. The increase was primarily due to increased oil and natural gas sales and improved oil prices as compared with the prior year, partially offset by a Colombian equity tax and increased operating and G&A expenses in 2011.
- Cash and cash equivalents was $351.7 million at December 31, 2011 compared with $355.4 million at December 31, 2010. The change in cash and cash equivalents during 2011 was primarily the result of $333.2 million of capital expenditures offset by funds flow from operations of $319.0 million and a decrease in non-cash working capital of $37.8 million during 2011.
- Working capital (including cash and cash equivalents) was $213.1 million at December 31, 2011, which is a $52.7 million decrease from December 31, 2010, due mainly to a $51.7 million increase in taxes payable due to increased taxable income in Colombia and a $40.9 million increase in accounts payable and accrued liabilities, partially offset by a $26.3 million increase in accounts receivable due to increased sales and a $14.5 million increase in taxes receivable. The increase in accounts payable and accrued liabilities is a result of operations acquired in the Petrolifera acquisition, the commencement of operations in Brazil and increased royalty payables as a result of increased production and higher realized prices. The increase in taxes receivable primarily relates to an increase in VAT receivable as a result of increased capital expenditures.
- Property, plant and equipment at December 31, 2011 was $1.0 billion, an increase of $317.8 million from December 31, 2010, as a result of the $327.6 million 2011 work program capital expenditures, $219.7 million of additions from the Petrolifera acquisition and $1.7 million of asset retirement obligations; partially offset by $231.2 million of DD&A expenses.

Business Combination

- On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. For further details reference should be made to Note 3 of the consolidated financial statements.
- The acquisition was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed were recorded at their fair values as at the acquisition date and the results of Petrolifera were consolidated with those of Gran Tierra from that date.
- The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)

Consideration Transferred:		
Common shares issued net of share issue costs	$	141,690
Replacement warrants		1,354
	$	143,044
Allocation of Consideration Transferred:		
Oil and gas properties		
Proved	$	58,457
Unproved		161,278
Other long term assets		4,417
Net working capital (including cash acquired of $7.7 million and accounts receivable of $6.4 million)		(17,223)
Asset retirement obligation		(4,901)
Bank debt		(22,853)
Other long term liabilities		(14,432)
Gain on acquisition		(21,699)
	$	143,044

As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, we reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, we recognized a "Gain on acquisition" of $21.7 million in the consolidated statement of operations. The gain reflects the impact on Petrolifera's pre-acquisition market value resulting from their lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

Production from the Petrolifera properties from the acquisition date to December 31, 2011 amounted to 1,811 BOEPD NAR with oil and natural gas sales of $32.5 million. For the post acquisition period, Petrolifera recorded an after tax loss of $8.0 million.

Business Environment Outlook

Our revenues have been significantly impacted by the continuing fluctuations in oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about financial markets and the impact of the worldwide economy on oil demand growth. However, based on projected production, prices, costs and our current liquidity position, we believe that our current operations and 2012 capital expenditure program can be maintained from cash flow from existing operations and cash on hand, barring unforeseen events or a severe downturn in oil and gas prices. Should our operating cash flow decline, we would examine measures such as reducing our capital expenditure program, issuance of debt, disposition of assets, or issuance of equity. The continuing uncertainty regarding the Middle East and Libya and continued economic instability in the United States and Europe is having an impact on world markets, and we are unable to determine the impact, if any, these events may have on oil prices and demand.

Our future growth and acquisitions may depend on our ability to raise additional funds through equity and debt markets. Should we be required to raise debt or equity financing to fund capital expenditures or other acquisition and development opportunities, such funding may be affected by the market value of our common stock. If the price of our common stock declines, our ability to utilize our stock to raise capital may be negatively affected. Also, raising funds by issuing stock or other equity securities would further dilute our existing shareholders, and this dilution would be exacerbated by a decline in our stock price. Any securities we issue may have rights, preferences and privileges that are senior to our existing equity securities. Borrowing money may also involve further pledging of some or all of our assets and will expose us to interest rate risk. Depending on the currency used to borrow money, we may also be exposed to further foreign exchange risk. Our ability to borrow money and the interest rate we pay for any money we borrow will be affected by market conditions, and we cannot predict what price we may pay for any borrowed money.

Consolidated Results of Operations

Consolidated Results of Operations *(Thousands of U.S. Dollars)*	2011	% Change	2010	% Change	2009
					Year Ended December 31,
Oil and natural gas sales	$ 596,191	60	$ 373,286	42	$ 262,629
Interest income	1,216	4	1,174	8	1,087
	597,407	60	374,460	42	263,716
Operating expenses	86,497	46	59,446	46	40,784
DD&A expenses	231,235	41	163,573	20	135,863
G&A expenses	60,389	50	40,241	40	28,787
Equity tax	8,271	–	–	–	–
Financial instruments (gain) loss	(1,522)	–	(44)	(123)	190
Gain on acquisition	(21,699)	–	–	–	–
Foreign exchange (gain) loss	(11)	–	16,838	(15)	19,797
	363,160	30	280,054	24	225,421
Income before income taxes	234,247	148	94,406	147	38,295
Income tax expense	(107,330)	88	(57,234)	135	(24,354)
Net income	$ 126,917	241	$ 37,172	167	$ 13,941
Production					
Oil and NGL's, bbl	6,118,705	17	5,228,554	13	4,621,546
Natural gas, Mcf	1,411,188	425	268,776	448	49,028
Total production, BOE[1]	6,353,903	20	5,273,350	14	4,629,717
Average Prices					
Oil and NGL's per bbl	$ 96.60	36	$ 71.19	25	$ 56.79
Natural gas per Mcf	$ 3.65	(6)	$ 3.90	(1)	$ 3.93
Consolidated Results of Operations ("per BOE")					
Oil and natural gas sales	$ 93.83	33	$ 70.79	25	$ 56.73
Interest income	0.19	(14)	0.22	(4)	0.23
	94.02	32	71.01	25	56.96
Operating expenses	13.61	21	11.27	28	8.81
DD&A expenses	36.39	17	31.02	6	29.35
G&A expenses	9.50	25	7.63	23	6.22
Equity tax	1.30	–	–	–	–
Financial instruments (gain) loss	(0.24)	–	(0.01)	(125)	0.04
Gain on acquisition	(3.42)	–	–	–	–
Foreign exchange (gain) loss	–	–	3.19	(25)	4.28
	57.14	8	53.10	9	48.70
Income before income taxes	36.88	106	17.91	117	8.26
Income tax expenses	(16.89)	56	(10.85)	106	(5.26)
Net income	$ 19.99	183	$ 7.06	135	$ 3.00

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

Consolidated Results of Operations for the Year Ended December 31, 2011 Compared with the Results for the Year Ended December 31, 2010

Net income was $126.9 million, or $0.46 per share basic and $0.45 per share diluted, in 2011 compared with $37.2 million, or $0.15 per share basic and $0.14 per share diluted, in 2010. Increased oil and natural gas sales due to increased production and higher realized oil prices, a $21.7 million gain on the Petrolifera acquisition and the absence of foreign exchange losses were partially offset by a $42.0 million impairment loss in the Peru cost center, a $25.7 million impairment loss in the Argentina cost center, a Colombian equity tax of $8.3 million and increased operating, DD&A and G&A expenses.

Oil and NGL production, NAR and inventory changes, in 2011 increased to 6.1 MMbbl, a 17% improvement compared with 5.2 MMbbl in 2010. The increase was due to improved production from the Moqueta, Jilguero and Juanambu fields, production from Petrolifera and the reduced impact of pipeline interruptions. Petrolifera's oil and NGL production for the period since the acquisition date, NAR, was 0.5 MMbbl. Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010 and February 7, 2011 which reduced sales through the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline"). During 2010, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 22 days.

Average realized oil prices in 2011 increased by 36% to $96.60 per barrel from $71.19 per barrel in 2010 reflecting higher West Texas Intermediate ("WTI") oil prices and the premium to WTI received in Colombia during 2011. Average WTI for 2011 was $95.06 as compared with $79.43 in 2010.

Increased production and higher oil prices resulted in a 60% increase in **revenue and other income** to $597.4 million for 2011 compared with $374.5 million in 2010.

Operating expenses for 2011 amounted to $86.5 million, or $13.61 per BOE, compared with $59.4 million or $11.27 per BOE, in 2010. The increase in operating expenses was mainly due to an increase of $18.3 million in operating costs in Argentina ($15.9 million related to properties acquired from Petrolifera), an increase of $7.7 million in Colombia and $1.0 million in Brazil as a result of expanded operations.

DD&A expenses for 2011 increased to $231.2 million compared with $163.6 million in 2010. DD&A expenses for 2011 includes a $42.0 million ceiling test impairment for our Peru cost center relating to seismic and drilling costs from two blocks which were relinquished, a $25.7 million impairment loss in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentine proved reserves and a decrease in reserve volumes and $18.4 million of depletion, depreciation and accretion related to properties acquired from Petrolifera. DD&A expenses in 2010 included a $23.6 million ceiling test impairment in our Argentina cost center, of which $17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations. The remaining small increase in DD&A was due to higher production levels and increased future development costs included in the depletable base, partially offset by an increase in year-end reserves as compared with 2010. On a BOE basis, DD&A in 2011 was $36.39 compared with $31.02 for 2010, representing a 17% increase resulting from ceiling test impairment losses and increased future development costs, partially offset by increased reserves.

G&A expenses of $60.4 million for 2011 were 50% higher than in 2010 due to increased employee related costs reflecting the expanded operations in all business segments, $1.2 million of expenses associated with the acquisition of Petrolifera and the inclusion of Petrolifera G&A expenses of $7.3 million (including interest on bank debt of $1.6 million, which was retired in August 2011). G&A expenses per BOE increased 25% to $9.50 per BOE compared with $7.63 per BOE for 2010 due to the same factors.

Equity tax represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years.

The **financial instruments gain** primarily relates to the fair value assigned to warrants issued in connection with the acquisition of Petrolifera. These warrants expired unexercised during August 2011.

The **gain on acquisition** of $21.7 million in 2011 relates to the acquisition of Petrolifera. This gain reflects the impact on Petrolifera's pre-acquisition market value of its lack of liquidity and capital resources required to maintain production and reserves and further develop and explore its inventory of prospects.

There were essentially no **foreign exchange gains** in 2011 as a result of an unrealized non-cash foreign exchange gain of $1.7 million being offset by realized foreign exchange losses. The non-cash foreign exchange gain primarily relates to the translation of deferred tax liabilities. This compares to a foreign exchange loss of $16.8 million recorded in 2010, of which $14.8 million was an unrealized non-cash foreign exchange loss. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation results in the recognition of unrealized exchange losses or gains. The Colombian Peso devalued by 1.5% against the U.S. dollar in the year ended December 31, 2011 resulting in an unrealized foreign exchange gain which was offset by realized foreign exchange losses. In 2010, the Colombian Peso strengthened against the U.S. dollar by 6%.

Income tax expense for 2011 was $107.3 million compared with $57.2 million in 2010. This represents an increase of 88%, primarily as a result of higher net income in Colombia. For the year ended December 31, 2011, the effective income tax rate was 46% compared with 61% in 2010 due to a decrease in non-taxable foreign currency translation adjustments and the non-taxable gain on acquisition in 2011, partially offset by an increase in the valuation allowance on deferred tax assets mainly in Peru. The variance in the effective tax rates compared with the 35% U.S. statutory rate is attributable to the same factors and other permanent differences.

Our capital expenditures during 2011 were $327.6 million (after changes in non-cash working capital and net of proceeds from disposition of oil and gas properties) representing a significant increase from capital expenditures in 2010 of $177.0 million. In 2011, we made capital expenditures included drilling and acquisition expenditures of $225.4 million, facilities expenses of $38.0 million, geological and geophysical expenses of $47.8 million and other expenditures of $16.4 million. Additionally, we had $219.7 million of additions to property, plant and equipment from the Petrolifera acquisition.

Consolidated Results of Operations for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

Net income of $37.2 million, or $0.15 per share basic and $0.14 per share diluted, was recorded in 2010 compared with $13.9 million, or $0.06 per share basic and $0.05 per share diluted, in 2009. A 42% increase in revenue and other income to $374.5 million from $263.7 million recorded in 2009 was partially offset by an $18.7 million increase in operating expenses, an $11.5 million increase in G&A expenses, a $27.7 million increase in DD&A, and a $32.9 million increase in income tax expense.

Revenue and other income increased 42% as a result of a 13% increase in oil production combined with a 25% improvement in oil prices.

Oil and NGL production, NAR, in 2010 increased to 5.2 MMbbl compared with 4.6 MMbbl in 2009, due to increased production from our Colombia operations. Average realized oil prices for 2010 increased to $71.19 per barrel from $56.79 per barrel in 2009, reflecting higher WTI oil prices.

The additional government royalty for the Costayaco Field (described in "Segmented Operations—Colombia") began in the fourth quarter of 2009 and was paid for only three months of 2009 versus the full year of 2010. As a result, our share of production was reduced by a total of 947,000 BOE's relating to this additional royalty in 2010 as compared with only 328,000 BOE in 2009. Since our production volumes are reported NAR and this royalty structure was not in place for an equal amount of time in 2009 and 2010, certain changes between these years, including volumes, changes in per BOE operating costs, and per BOE general and administrative costs, are not readily comparable. For instance, the increase in the Costayaco field production does not appear as high in comparison with 2009 as it would appear without the additional royalty volumes deducted. Similarly, the per BOE operating and G&A expenses appear higher on a per BOE basis in 2010 than in 2009 as the costs are divided over a smaller base after royalties are deducted.

Operating expenses for 2010 amounted to $59.4 million, a 46% increase from the prior year total of $40.8 million. The increase in operating expenses occurred primarily in Colombia and was due to an enhanced workover program related to the Costayaco area, an increase in transportation costs related to increased production and pipeline maintenance, and an increase in producing wells in Costayaco. Operating expenses on a BOE basis in 2010 were $11.27, a 28% increase from 2009 reflecting both the increase in total operating costs and the effect of the additional government royalty payable on per BOE calculations, partially offset by an increase in production.

DD&A expenses for 2010 increased to $163.6 million compared with $135.9 million in 2009. The increase in production levels was partially offset by an increase of reserves at year-end and a reduction of future development costs included in the depletable base as compared with 2009. DD&A expenses in 2010 included a $23.6 million ceiling test impairment for our Argentina cost center, of which $17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations, as compared with a $1.9 million charge in 2009. On a BOE basis, DD&A in 2010 was $31.02 compared with $29.35 for 2009, representing a 6% increase resulting from the ceiling test impairment loss offset partially by increased reserves and decreased future development costs.

G&A expenses of $40.2 million for 2010 were 40% higher than 2009 due to increased employee related costs reflecting the expansion of operations in Peru, Brazil, and Colombia and higher business development costs. G&A expenses per BOE increased 23% to $7.63 per BOE compared with $6.22 per BOE for 2009. The increase in G&A expenses on a per BOE basis over the prior year was compounded by the additional royalty paid in 2010.

The **foreign exchange loss** of $16.8 million for 2010, of which $14.8 million is an unrealized non-cash foreign exchange loss, compares to $19.8 million recorded in 2009, of which $19.5 million is an unrealized non-cash foreign exchange loss. These losses originate in Colombia and relate to foreign exchange losses resulting from the translation of a deferred tax liability.

Income tax expense for 2010 amounted to $57.2 million compared with $24.4 million recorded in 2009. This represents an increase of 135% in annual income tax expense, primarily as a result of higher profits and the application of a valuation allowance against previously recognized deferred tax assets associated with Argentina. The decrease in the 2010 effective tax rate to 61% from 64% in 2009 is primarily due to a decrease in the valuation allowance associated with losses in our U.S., Canadian, Peru and Brazil business units, partially offset by the increase in the valuation allowance associated with losses in our Argentina business units. The variance from the 35% U.S. statutory rate for 2010 results from foreign currency translation losses that are neither taxable nor deductible for tax purposes in each of the respective jurisdictions, the valuation allowances as described above, enhanced tax depreciation incentive in Colombia, and Colombia third party royalty payments that are not deductible for tax purposes. Similar factors cause the variance from the 35% U.S. statutory rate for 2009.

Estimated Oil and Gas Reserves

Estimated proved oil and NGL reserves, NAR, as of December 31, 2011, were 30.9 MMbbl, a 31% increase from the estimated proved reserves as at December 31, 2010. The increase was due to the acquisition of Petrolifera which had reserves in Argentina and Colombia, positive technical revisions to Costayaco reserves (based on reservoir performance), the drilling of additional appraisal wells in the Moqueta field and the acquisition of a 70% working interest in Block 155 in Brazil, which more than offset 2011 oil production. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2011 were 10.5 MMbbl and 17.6 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2011, were 18.3 Bcf compared with 1.2 Bcf at December 31, 2010. The increase was due to the acquisition of Petrolifera. At December 31, 2011, 75% of proved gas reserves were in the Sierra Nevada Block and 19% were in the Puesto Morales Blocks, both of which were acquired in the Petrolifera acquisition. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2010, were 23.6 MMbbl, a 7 % increase from the estimated proved reserves as at December 31, 2009. The increase was generated by our Colombian operations and resulted from our exploration success in Moqueta and from sustained reservoir performance in Costayaco, which led to conversion of probable reserves to proved reserves and which more than offset 2010 production of oil. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2010 were 7.4 MMbbl and 16.3 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2010, were 1.2 Bcf, a 37 % decrease from the estimated proved reserves as at December 31, 2009. Estimated probable and possible gas reserves, NAR, as of December 31, 2010 were 0.1 Bcf and 42.1 Bcf, respectively.

2012 Work Program and Capital Expenditure Program

In December 2011, we announced the details of our 2012 capital program. We have planned a 2012 capital budget of $367 million, including $182 million for Colombia, $68 million for Brazil, $53 million for Argentina, $62 million for Peru and $2 million associated with corporate activities. Of this, $246 million is for drilling, $39 million is for facilities, equipment and pipelines and $82 million is for geological and geophysical ("G&G") expenditures. Of the $246 million allocated to drilling, approximately $152 million is for exploration, and the balance is for delineation and development drilling.

We expect that our committed and discretionary 2012 capital program will be funded from cash flow from operations and cash on hand.

Our 2012 work program is intended to create both growth and value through strategic acquisitions of working interests, by leveraging existing assets to increase reserves and production levels and through the construction of pipelines and facilities in the areas with proved reserves. We are financing our capital program through cash flows from operations and cash on hand, while retaining financial flexibility with a strong cash position and no debt, so that we can be positioned to undertake further development opportunities and to pursue value-add acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds will be expended as set forth in our 2012 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Excluding potential exploration success, production in 2012 is expected to range between 20,000 and 21,000 BOEPD NAR.

Segmented Results—Colombia

Segmented Results of Operations—Colombia *(Thousands of U.S. Dollars)*				Year Ended December 31,			
	2011	% Change	2010	% Change	2009
Oil and natural gas sales	**$ 543,999**	51	$ 359,302	44	$ 248,834
Interest income	**492**	7	460	(1)	466
	544,491	51	359,762	44	249,300
Operating expenses	**58,081**	15	50,431	52	33,091
DD&A expenses	**141,133**	6	133,728	5	127,213
G&A expenses	**25,116**	65	15,216	17	13,011
Equity tax	**8,271**	–	–	–	–
Foreign exchange (gain) loss	**(1,626)**	(109)	17,901	(11)	20,158
	230,975	6	217,276	12	193,473
Income before income taxes	**$ 313,516**	120	$ 142,486	155	$ 55,827
Production					
Oil and NGL's, bbl	**5,348,885**	8	4,944,510	15	4,284,230
Natural gas, Mcf	**267,612**	–	268,776	448	49,028
Total production, BOE[1]	**5,393,487**	8	4,989,306	16	4,292,401
Average Prices					
Oil and NGL's per bbl	**$ 101.42**	40	$ 72.45	25	$ 58.04
Natural gas per Mcf	**$ 5.72**	47	$ 3.90	(1)	$ 3.93
Segmented Results of Operations per BOE					
Oil and natural gas sales	**$ 100.86**	40	$ 72.01	24	$ 57.97
Interest income	**0.09**	–	0.09	(18)	0.11
	100.95	40	72.10	24	58.08
Operating expenses	**10.77**	7	10.11	31	7.71
DD&A expenses	**26.17**	(2)	26.80	(10)	29.64
G&A expenses	**4.66**	53	3.05	1	3.03
Equity tax	**1.53**	–	–	–	–
Foreign exchange (gain) loss	**(0.30)**	(108)	3.59	(24)	4.70
	42.83	(2)	43.55	(3)	45.08
Income before income taxes	**$ 58.12**	104	$ 28.55	120	$ 13.00

(1) Production represents production volumes NAR adjusted for inventory changes. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices

Segmented Results of Operations—Colombia for the Year Ended December 31, 2011 Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **income before income taxes** from Colombia amounted to $313.5 million compared with income before taxes of $142.5 million recorded in 2010. The increase is mainly due to increased oil sales due to increased production and higher prices and a foreign exchange gain, partially offset by increases in operating, DD&A and G&A expenses and Colombian equity tax of $8.3 million.

In 2011, **production of oil and NGLs**, NAR, increased by 8% to 5.3 MMbbl compared with 4.9 MMbbl in 2010. The increase in production is primarily due to the development of the Moqueta field with six producing wells, the commencement of production in the Garibay Block from the Jilguero -1 and -2 wells and increased production in the Guayuyaco Block from the new well Juanambu -3 and a full year of production from Juanambu -2. Production from the Costayaco field was consistent with the prior year. Production from two new wells, Costayaco-12 and -13, was offset by the effects of reservoir management intended to slow production declines.

Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010 and February 7, 2011 which reduced sales through the OTA pipeline. During 2010, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 29 days (7 days in June and 22 days in September).

As a result of achieving gross field production of five MMbbl in our Costayaco field in the fourth quarter of 2009, we are subject to an additional government royalty payable. This royalty is calculated on 30% of field production revenue over an inflation adjusted trigger point. That trigger point for Costayaco oil was $31.29 for 2011. Production revenue for this calculation is based on production volumes net of other government royalty volumes. Average government royalties at Costayaco with gross production of 17,000 barrels of oil per day and $100 WTI price per barrel are approximately 27.9%, including the additional government royalty of approximately 20.5%. The ANH sliding scale royalty at 17,000 barrels of oil per day is approximately 9.2% and this royalty is deductible prior to calculating the additional government royalty.

Revenue and other income in 2011 increased by 51% to $544.5 million compared with 2010. Oil and natural gas sales were positively impacted by higher net realized oil prices in 2011 and increased production. The average net realized price for oil in 2011 was $101.42 per barrel, an increase of 40% from 2010. We received a premium to WTI during 2011 related to Colombian Pacific Blend prices.

Operating expenses for the year ended December 31, 2011 increased to $58.1 million, or $10.77 per BOE, from $50.4 million, or $10.11 per BOE in 2010. Operating expenses per BOE were higher in 2011 due to long-term testing and slickline service costs partially offset by reduced transportation and workover costs. Significant long-term testing costs were incurred at Jilguero -1 and slickline service costs at Costayaco and Moqueta. Transportation costs were 11% lower than the prior year due to lower trucking costs as a result of the reduced impact of pipeline disruptions and pipeline pumping optimization. Workover costs were 45% lower than the prior year mainly due to fewer workovers in the Chaza Block. Petrolifera's operating expenses for the post acquisition period were $1.2 million.

For 2011, **DD&A expenses** increased to $141.1 million from $133.7 million in 2010. Petrolifera's DD&A expense for the post acquisition period was $4.3 million. The remainder of the increase was attributable to higher production levels partially offset by a small reduction in the depletion rate to $26.17 per BOE compared with $26.80 per BOE in 2010. Increased costs in our depletable pools were offset by higher reserves.

G&A expenses increased to $25.1 million ($4.66 per BOE) from $15.2 million ($3.05 per BOE) in 2010. The increase was mainly due to increased salaries and stock-based compensation resulting from an increased headcount, the inclusion of Petrolifera's G&A expense of $3.2 million and consulting fees related to expanded operations.

Equity tax of $8.3 million in 2011 represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period.

The results for 2011 include a **foreign exchange gain** of $1.6 million, of which $0.9 million is an unrealized non-cash foreign exchange gain on the translation of Colombian peso denominated deferred taxes to the U.S. dollar functional currency. For 2010, the foreign exchange loss was $17.9 million, of which $14.6 million was unrealized. The Colombian Peso devalued by 1.5% against the U.S. dollar in the year ended December 31, 2011 resulting in the unrealized foreign exchange gain. In 2010, the Colombian Peso strengthened against the U.S. dollar by 6%. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

Segmented Results of Operations—Colombia for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

For the year ended December 31, 2010, **income before income taxes** from Colombia amounted to $142.5 million compared with income before taxes of $55.8 million recorded in 2009. An increase in production revenue more than offset increased operating, G&A, and DD&A expenses.

For the year ended December 31, 2010, **production of oil and NGLs**, NAR, increased by 15% to 4.9 MMbbl compared with 4.3 MMbbl in 2009. The increase in production is primarily due to the increase in wells on stream in Costayaco and the success of the Costayaco workover program. Production levels are after government royalties ranging from 8% to 26% and third party royalties of 2% to 10%. The additional government royalty paid in 2010 (discussed above) reduced the increase in total production from the Costayaco field as compared with the prior year.

Our Colombian operating results for the year ended December 31, 2010 were principally driven by the increase in production volumes and the associated increase in workover, transportation, operating, G&A and DD&A expenses. In 2010, Colombia production included Costayaco -1, -2, -3, -4, -8, -9, -10 (January 2010), and -11 (June 2010), Juanambu -1 and -2, and the Santana Block. In 2009, Colombia production included Costayaco –1,-2,-3,-4,-5, -8 (July 2009), -9 (September 2009), and Juanambu -1.

Outages on the OTA pipeline result when sections of the pipeline are damaged. Outages reduced our deliveries to Ecopetrol for 29 days in 2010 (7 days in June and 22 days in September), as compared with 46 days in 2009 (32 days in July and August and 14 days in June). In January 2009, the Juanambu and Costayaco fields were also shut in for 10 days due to a general strike in the region where our operations are located. The overall decrease in sales as a result of the disruptions is estimated to be approximately 2% of total sales in 2010 and 14% of total sales in 2009.

Revenue and interest were positively affected by an increase in net realized oil prices in 2010 compared with 2009. The average net realized prices for oil, which are based on WTI prices, increased by 25% to $72.45 per barrel for the year ended December 31, 2010 compared with 2009. Increased production combined with the increased net realized oil price resulted in our revenue and interest from Colombia for the year ended December 31, 2010 increasing by 44% to $359.8 million from 2009 levels.

As a result of achieving gross field production of five million barrels in our Costayaco field during the month of September 2009, we became subject to an additional government royalty payable. The additional royalty is calculated on 30% of the field production revenue over an inflation adjusted trigger point. That trigger point was $32.13 for 2010 and $30.22 for 2009. Production revenue for this calculation is based on production volumes net of other government royalty volumes. In 2010, the actual government royalties at Costayaco averaged 24% including the additional government royalty of 15%. In 2009, the government royalties for the year averaged 16%, including the additional government royalty, once it became effective September 2009.

Operating expenses for the year ended December 31, 2010 increased to $50.4 million from $33.1 million in 2009. The increased operating expenses resulted from the Costayaco workover program ($6.6 million higher than in 2009), increased trucking resulting from increased volumes and OTA pipeline maintenance, and an increase in producing wells in Costayaco for 2010. On a per BOE basis, operating expenses for 2010 increased to $10.11 compared with $7.71 incurred in 2009, reflecting higher operating costs partially offset by the effect of the increase in total production. The additional government royalty paid in 2010 as compared with 2009 further increased the per BOE operating cost amounts from 2009.

For 2010, **DD&A expenses** increased to $133.7 million from $127.2 million in 2009. Increased production levels partially offset by higher oil reserve levels and lower future development costs added to the depletable base, accounted for the increase in DD&A expenses. On a per BOE basis, DD&A expenses in Colombia decreased by 10% to $26.80 for 2010, compared with $29.64 for 2009, due to higher production offset by increased proved reserves and lower future development costs.

Higher **G&A expenses** incurred to manage the increased level of development and operating activities resulted in G&A expense increasing to $15.2 million for the year ended December 31, 2010 from $13.0 million incurred in 2009. On a per BOE basis, G&A expenses in 2010 increased by 1% to $3.05 from $3.03 in 2009, due to higher costs partially offset by higher production. The additional government royalty paid in 2010 as compared with 2009 further increased the per BOE G&A amounts from 2009.

The **foreign exchange loss** of $17.9 million for the year ended December 31, 2010 includes an unrealized non-cash foreign exchange loss of $14.6 million and compares to a foreign exchange loss of $20.2 million in 2009, including an unrealized non-cash foreign exchange loss of $19.3 million. The unrealized non-cash foreign exchange loss resulted primarily from the translation of a deferred tax liability recognized on the purchase of Solana Resources Limited ("Solana"). This deferred tax liability, a monetary liability, is denominated in the local currency of the Colombian foreign operations and as a result, foreign exchange gains and losses have been calculated on conversion to the U.S. dollar functional currency.

Capital Program—Colombia

The Petrolifera acquisition added interests in three blocks in Colombia: the Sierra Nevada Block and the Magdalena Block in the Lower Magdalena Basin and the Turpial Block in the Middle Magdalena Basin.

Capital expenditures in Colombia during 2011 were $202.6 million, an increase of 92% from 2010. The following table provides a breakdown of capital expenditures during 2011, 2010 and 2009:

Segmented Capital Program—Colombia *(Millions of U.S. Dollars)*	Year Ended December 31, 2011	2010	2009
Drilling and completion	$ 105.3	$ 60.2	$ 46.0
Facilities and equipment	33.0	25.2	14.7
Geological and geophysical	30.0	22.0	15.1
Other	34.3	(1.9)	5.6
	$ 202.6	$ 105.5	$ 81.4

The significant elements of our 2011 Capital Program in Colombia were as follows:

Costayaco Field, Chaza Block (100% working interest and Operator)
We completed three development wells in the Costayaco field. The Costayaco -12 and -13 development wells were drilled as infill production wells to test the respective northern and southern extensions of the Costayaco field. Production from these wells is intended to assist in maintaining the production plateau at the Costayaco field; these wells will be converted to water-injectors to assist with pressure maintenance in the field later in the Costayaco field life. The Costayaco-14 development well was completed as a water injector well for pressure support in the Costayaco field.

We completed upgrades to the pumping station, battery and support facilities and a project to electrify the field was completed in December 2011.

Moqueta Field, Chaza Block (100% working interest and Operator)
We completed three development wells in the Moqueta field, Moqueta -4, -5 and -6. All three wells are currently on production. The Moqueta -4 development well was successfully completed and tested 1,674 BOPD confirming additional oil bearing reservoirs. The Moqueta -5 development well resulted in production rates of 730 barrels of oil per day. The Moqueta -6 development well was drilled and tested 144 BOPD natural flow.

Construction of facilities at the Moqueta field commenced in 2011. In 2011, the 6-inch diameter, 8 km pipeline connecting the Moqueta and Costayaco infrastructure was completed. We also completed a parallel 4-inch gas line that will be used to transport gas or water from Costayaco to Moqueta for anticipated gas injection for pressure support.

We commenced the acquisition of 3D seismic to assist in refining the mapping of the Moqueta field and planning further delineation and development drilling.

Guayuyaco Block (70% working interest and Operator)
The Juanambu -3 development well was completed as a producing well. We acquired 77 square kilometers of 3D seismic and acquired pumping equipment.

Garibay Block (50% non-operated working interest)
The Melero -1 exploration well was drilled and completed and resulted in an oil discovery. The Jilguero -2 development well was also completed as a producing well. Both of these wells will begin long-term testing in the first quarter of 2012. We also completed civil works and upgraded facilities.

Other Prospects
During 2011, we completed the following exploration wells: Canangucho -1 and Pacayaco -1ST1 on the Chaza Block, San Angel -1001 on the Magdalena Block, Taruka -1 on the Piedemonte Sur Block and Rumiyaco -1 on the Rumiyaco Block. These wells were plugged and abandoned in 2011. We also drilled the Brillante SE -2 development well on the Sierra Nevada Block, but no reservoir was present, so the well was plugged and abandoned. We also completed a 275 square kilometer 3D seismic survey. Approximately 222 square kilometers of data was acquired in the Sierra Nevada license and 53 square kilometers in the Magdalena license.

Capital expenditures in Colombia for the year ended December 31, 2010 amounted to $105.5 million and included: Costayaco facilities and site preparation and drilling for Costayaco -11, -12 and -13, Moqueta -1, -2, -3 and -4, Pacayaco -1ST1 and Canangucho -1; Juanambu -2 drilling and facilities, Taruka -1, Popa -3 drilling and 3D and 2D seismic.

Outlook—Colombia

The 2012 capital program in Colombia is $182 million with $104 million allocated to drilling, $27 million to facilities and pipelines and $51 million for G&G expenditures. Our planned work program for 2012 includes the following:

Exploration Activities
The 2012 exploration program in Colombia includes four gross exploration wells. Our oil exploration drilling program will target prospects in the Putumayo and Llanos basins. The Ramiriqui-1 oil exploration well on the Llanos-22 Block operated by CEPSA began drilling in the fourth quarter of 2011. The mirador formation has been interpreted as oil bearing. Casing has been set and drilling is continuing in order to evaluate deeper potential reservoirs. We plan to perform testing after the completion of drilling.

We plan to drill the Bordon -1 oil exploration well to the north of the Melero and Jilguero discoveries on the Garibay Block, the Verdeyaco -1 oil exploration well on the Guayuyaco Block and the La Vega Este-1 oil exploration well on the Azar Block.

Development and Delineation Activities

The 2012 development program in Colombia includes seven gross development wells. Our development drilling will focus on the Moqueta, Costayaco and Brillante field developments. In the Costayaco field, we plan to drill two additional water injector wells along with two production wells. In the Moqueta field, we plan to drill one development well, which could be used as an oil producer or water injector depending on the well results, and a further water injector well. We also plan to drill the Brillante -3 natural gas delineation well in the Sierra Nevada Block.

Facilities and Equipment

Facilities work will include continued electrification of the Moqueta fields, water injection facilities and a production battery at the Jilguero oil discovery.

G&G

G&G work will consist of 3D and 2D seismic planned for the Cauca -6, Cauca -7, Moqueta, Garibay, Piedemonte Norte, Piedemonte Sur, Putumayo -1 and Putumayo -10 Blocks to mature leads and prospects for drilling in 2013 and beyond.

Segmented Results—Argentina

	Year Ended December 31,				
Segmented Results of Operations—Argentina *(Thousands of U.S. Dollars)*	**2011**	% Change	2010	% Change	2009
Oil and natural gas sales	**$ 48,016**	243	$ 13,984	1	$ 13,795
Interest income	**66**	154	26	(80)	127
	48,082	243	14,010	1	13,922
Operating expenses	**27,076**	207	8,808	17	7,537
DD&A expenses	**45,506**	55	29,416	253	8,339
G&A expenses	**7,805**	172	2,868	24	2,318
Foreign exchange (gain) loss	**330**	100	165	493	(42)
	80,717	96	41,257	127	18,152
Loss before income taxes	**$ (32,635)**	(20)	$ (27,247)	(544)	$ (4,230)
Production					
Oil and NGL's, bbl	**726,762**	156	284,044	(16)	337,316
Natural gas, Mcf	**1,143,576**	–	–	–	–
Total production, BOE[1]	**917,358**	223	284,044	(16)	337,316
Average Prices					
Oil and NGL's per bbl	**$ 61.10**	24	$ 49.23	20	$ 40.90
Natural gas per Mcf	**$ 3.16**	–	$ –	–	$ –
Segmented Results of Operations per BOE					
Oil and natural gas sales	**$ 52.34**	6	$ 49.23	20	$ 40.90
Interest income	**0.07**	(22)	0.09	(76)	0.38
	52.41	6	49.32	19	41.28
Operating expenses	**29.52**	(5)	31.01	39	22.34
DD&A expenses	**49.61**	(52)	103.56	319	24.72
G&A expenses	**8.51**	(16)	10.10	47	6.87
Foreign exchange (gain) loss	**0.36**	(38)	0.58	(583)	(0.12)
	88.00	(39)	145.25	170	53.81
Loss before income taxes	**$ (35.59)**	(63)	$ (95.93)	666	$ (12.53)

(1) Production represents production volumes NAR adjusted for inventory changes. Gas volumes are converted to BOE equivalent at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

Segmented Results of Operations—Argentina for the Year Ended December 31, 2011 Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **loss before income taxes** in Argentina amounted to $32.6 million compared with $27.2 million in 2010. Loss before income tax included a ceiling test impairment charge for the Argentina cost center of $25.7 million in 2011 and $23.6 million in 2010. In 2011, increased oil and natural gas sales were more than offset by increased operating, depletion and G&A expenses and an increase in the foreign exchange loss. Results of the Argentina segment were significantly affected by the inclusion of Petrolifera's results since the acquisition date. The impact of Petrolifera on the financial and operational results of the Argentina segment is discussed below.

Oil and NGL production NAR increased 156% to 0.7 MMbbl compared with 0.3 MMbbl for 2010. The increase resulted from the inclusion of Petrolifera production of 0.5 MMbbl, NAR, in 2011.

Natural gas sales NAR relate solely to Petrolifera's properties. Natural gas sales amounted to 1.1 Bcf in 2011.

Overall, total production of oil and gas from the Argentina segment increased by 223% to 0.9 MMBOE in 2011.

Due to the Argentinean regulatory regime, the average oil price we received for production from our blocks during 2011 was approximately $61.10 per barrel. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short term basis.

Revenue and other income increased by 243% to $48.1 million in 2011 compared with $14.0 million in 2010. The increase was primarily due to higher production due to the inclusion of Petrolifera's oil and gas production and increased prices. Average regulated oil prices increased by 24% in 2011 compared with 2010. The Argentine segment realized $0.6 million from the sale of Petroleum Plus program credits during the fourth quarter of 2011. These credits are granted by the Argentine government to companies for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

Operating expenses in 2011 amounted to $27.1 million compared with $8.8 million in 2010. Petrolifera's operating expenses were $15.9 million in 2011. Operating expenses were $29.52 per BOE in 2011 compared with $31.01 per BOE in 2010. Transportation costs decreased by $1.91 per BOE a result of a higher percentage of production being from blocks with lower per BOE transportation costs, such as the Puesto Morales Block.

DD&A expenses in 2011 were $45.5 million compared with $29.4 million in 2010. DD&A expenses included a ceiling test impairment charge for the Argentina cost center of $25.7 million in 2011 and $23.6 million in 2010. The impairment loss in 2011 resulted from an increase in estimated future operating and capital costs to produce our remaining Argentine proved reserves and a decrease in reserve volumes. The impairment loss in 2010 included $17.9 million relating to the abandonment of the sidetrack operations at the GTE.St.VMor-2001 well and $5.2 million resulting from reduced reserves due to increases in estimated future operating costs. Petrolifera's depreciation, depletion and accretion expense was $14.0 million in 2011. DD&A expenses per BOE in 2011 were $49.61, significantly lower than DD&A expenses in 2010 of $103.56 due to the ceiling test impairment charge of $81.28 per BOE compared with $28.02 in 2011.

G&A expenses in 2011 were $7.8 million compared with $2.9 million in 2010. The increase was primarily due to the inclusion of Petrolifera's G&A for the period after acquisition ($3.2 million, including interest expense on bank debt of $1.6 million which was repaid in August 2011) and increased headcount and consulting fees as a result of expanded operations.

Segmented Results of Operations—Argentina for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

For the year ended December 30, 2010, **loss before income taxes** in Argentina was $27.2 million compared with $4.2 million in 2009 due to lower production levels and increased operating, depletion and G&A expenses, only partially offset by increased oil prices. Operating expenses increased due primarily to costs associated with Valle Morado, which had limited operating costs in 2009, prior to re-entry in the third quarter of 2010. DD&A included charges for ceiling test impairment of the Argentina cost center of $23.6 million in 2010 and $1.9 million in 2009. General and administrative expenses increased due to an increase in staffing and consulting fees over 2009 levels.

Crude oil and NGL production, net after 12% royalties, decreased 16% to 0.3 mmbbl in 2010 compared with 2009. The decrease resulted from general production declines.

Capital Program—Argentina

Capital expenditures in Argentina amounted to $36.3 million in 2011. Capital expenditures in 2011 included drilling expenditures of $27.1 million, facilities expenses of $4.0 million, G&G expenses of $2.6 million and other expenditures of $2.6 million. These expenditures were partially offset by proceeds of $3.3 million from the farm out of a property and $1.2 million from the sale of a blow-out preventer. The Petrolifera acquisition added interests in seven blocks in the Neuquen Basin in Argentina of which we still hold six.

The significant elements of our 2011 Capital Program in Argentina were as follows:

Puesto Morales Block (100% working interest and operator)
We completed drilling a development well in the Puesto Morales field, with the purpose of improving recovery and growing production from this mature oil field. We completed workovers on 18 wells and completed G&G work to optimize the location of the planned development wells. We also continued facility upgrades.

Puesto Morales Este Block (100% working interest and operator)
We drilled and completed two producing development wells.

Rinconada Norte Block (35% non-operated working interest)
Our partner commenced drilling four gross exploration wells. Two wells were completed in 2011, which resulted in an oil discovery, and two were in progress at year-end. A wholly-owned subsidiary of America Petrogas Inc. is the operator of this block with a 65% working interest upon completing certain work program obligations, while we hold a 35% working interest.

Rinconada Sur Block (100% and operator)
We started drilling one development well.

Surubi Block (85% working interest and operator)
We performed site preparation work for the Proa -2 development well and associated facilities to produce the new well and completed workover activities at the Proa -1 discovery well.

El Chivil Block
We completed a workover program in El Chivil which helped stabilize production.

Palmar Largo Block (14% non-operated working interest
One gross development well was drilled and workover activities were completed.

Santa Victoria Block (50% working interest and operator)
We successfully farmed out a 50% interest in the Santa Victoria Block in the Noroeste Basin of northwestern Argentina to Apache in March 2011. The joint venture, with Gran Tierra as operator, is evaluating the gas potential of the acreage, with gas-condensate reserves and production proven in the region. We have agreed to proceed with Apache into the second exploration phase, which has a work commitment that will be fulfilled with one exploration well expected to be drilled before year-end 2012.

Valle Morado Block (96.6% working interest and operator)
The sidetrack drilling operation on the Valle Morado GTE.St.VMor-2001 well was suspended in February 2011 and the wellbore was abandoned due to operational challenges.

We also continued to evaluate other blocks and bids for potential acquisitions.

Capital expenditures for the year ended December 31, 2010 amounted to $33.9 million and included exploratory seismic in the Santa Victoria Block for $3.9 million, a $2.7 million workover in El Chivil and $24.4 million related to the re-entry and sidetrack of the GTE.St.VMor-2001 well, including $2.0 million to buy out our partner's option to back in for an additional working interest.

Capital expenditures for the year ended December 31, 2009 amounted to $4.5 million mainly related to workovers, facility construction, and seismic acquisition.

Outlook—Argentina

The 2012 capital program in Argentina is $53 million with $39 million allocated to drilling, $6 million to facilities and pipelines, and $8 million to G&G expenditures.

Our planned work program for 2012 includes drilling three gross exploration wells, 10 gross development wells and conducting 14 workovers on existing wells in Argentina. Eight gross development wells are planned for the Puesto Morales Field, one on the Surubi Block and one on the Rinconada Sur Block. The intention of the drilling program is to improve recovery of oil in place and grow production. We plan to drill two oil exploration wells on the Rinconada Sur Block and are also evaluating the potential to drill a gas exploration well in the Santa Victoria Block in 2012.

Segmented Results—Peru

					Year Ended December 31,
Results of Operations—Peru *(Thousands of U.S. Dollars)*	**2011**	% Change	2010	% Change	2009
Interest income	**$ 140**	–	$ –	–	$ –
Operating expenses	**322**	55	207	149	83
DD&A expenses	**42,035**	–	40	–	–
G&A expenses	**4,249**	269	1,153	272	310
Foreign exchange (gain) loss	**(217)**	(823)	30	900	3
	46,389	–	1,430	261	396
Loss before income taxes	**$ (46,249)**	–	$ (1,430)	261	$ (396)

Segmented Results of Operations—Peru for the Year Ended December 31, 2011 Compared with the Results for the Year Ended December 31, 2010

Due to the significance of losses before income taxes, Peru became a reportable segment in 2011. The comparative amounts for 2010 were disaggregated from the "All Other" category for presentation purposes.

DD&A expenses in 2011 includes a $42.0 million ceiling test impairment for our Peru cost center relating to seismic and drilling costs from two blocks which were relinquished.

The increase in **G&A expenses** in 2011 from 2010 was due to higher salaries, stock-based compensation and consulting fees resulting from increased activity. We are now the operator of three exploration blocks in Peru and have a non-operated interest in two other blocks.

Capital Program—Peru

The Petrolifera acquisition added three blocks in the Ucayali Basin in Peru: Block 106, Block 107 and Block 133. Prior to close of the acquisition, Petrolifera, in consultation with Gran Tierra, notified PeruPetro of the intention not to proceed to the next exploration phase in Block 106. Accordingly, the Block 106 license agreement was terminated in April 2011.

Capital expenditures in Peru during the year ended December 31, 2011 were $36.2 million. The significant elements of our 2011 Capital Program in Peru were as follows:

Blocks 123, 124 and 129 (20% non-operated working interest)
In September 2010, we acquired a 20% non-operated working interest in ConocoPhillips operated Block 123, Block 124 and Block 129, subject to government approval. The approval for these blocks was granted in March 2011 with final assignment completed on April 26, 2011. We relinquished our interest in Block 124 during 2011. We acquired 910 kilometers of 2D seismic data on these blocks in 2011.

Blocks 107 and 133 (100% working interest and operator)
Permitting for drilling on Block 107 was advanced. G&G studies are ongoing on the adjacent Block 133 in preparation for seismic geophysical acquisition in 2012.

Blocks 122 and 128
We drilled the Kanatari -1 exploration well on Block 128 which was plugged and abandoned. We relinquished our interest in Blocks 122 and 128 during 2011.

Capital expenditures in Peru during the year ended December 31, 2010 were $15.0 million and mainly related to the acquisition of seismic data, a $2.0 million deposit on the farm-in of Block 95 in Peru and commencement of drilling on Blocks 122 and 128.

Capital expenditures in Peru during the year ended December 31, 2009 were $1.6 million and included drilling feasibility and geological studies on Block 122 and Block 128.

Outlook—Peru

The Peru budget of $62 million includes drilling one gross exploration well on Block 95 and preparations for drilling a second exploration well in 2013. Drilling costs are anticipated to be $41 million and approximately $21 million is budgeted for seismic acquisition and facility costs.

On January 17, 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block to Gran Tierra. A drilling location has been identified for the first exploration well on Block 95, with civil construction initiated. Drilling is expected to be undertaken in 2012.

Results—Corporate Activities and Operations in Brazil

Results of Operations—Corporate Activities and Operations in Brazil (Thousands of U.S. Dollars)	Year Ended December 31, 2011	% Change	2010	% Change	2009
Oil and natural gas sales	$ 4,176	–	$ –	–	$ –
Interest income	518	(25)	688	39	494
	4,694	582	688	39	494
Operating expenses	1,018	–	–	(100)	73
DD&A expenses	2,561	558	389	25	311
G&A expenses	23,219	11	21,004	60	13,148
Financial instruments (gain) loss	(1,522)	–	(44)	123	190
Gain on acquisition	(21,699)	–	–	–	–
Foreign exchange (gain) loss	1,502	219	(1,258)	291	(322)
	5,079	(75)	20,091	50	13,400
Loss before income taxes	$ (385)	(98)	$ (19,403)	50	$ (12,906)

Results of Operations—Corporate Activities and Operations in Brazil for the Year Ended December 31, 2011 Compared with the Results for the Years Ended December 31, 2010 and December 31, 2009

Corporate activities include costs associated with our headquarters in Calgary, Alberta, Canada, and expenses related to technical reviews, business development and compliance and reporting under securities regulations.

Oil and natural gas sales and **operating expenses** represent sales and operating expense from Block 155 in the onshore Recôncavo Basin of Brazil. We began earning revenue from this block on June 15, 2011, the date regulatory approval was received for the purchase of our 70% participating interest in that block.

DD&A expenses in 2011 of $ 2.6 million included $1.8 million in Brazil. This related primarily to Block 155 which began production during the year.

The increase in **G&A expenses** of $ 2.2 million between 2011 and 2010 related to increased salary and stock-based compensation expense and increased consulting charges due to expanded operations in all countries. The 2011 expenses included $1.2 million related to the acquisition of Petrolifera. The increase between 2009 and 2010 was due to increased staffing levels to support business development activities and expanded operations and Brazil as well as higher stock based compensation expense due to increased stock option grants.

The **financial instruments gain** in 2011 primarily related to the fair value of warrants issued in connection with the acquisition of Petrolifera. These warrants expired unexercised during August 2011. In 2010, we recorded a gain of $44,000 compared with a loss of $0.2 million in 2009. We had no derivative contracts outstanding at December 31, 2011 or 2010.

The **gain on acquisition** related to the acquisition of Petrolifera. The gain reflected the impact on Petrolifera's pre-acquisition market value of their lack of liquidity and capital resources required to maintain production and reserves and further develop and explore their inventory of prospects.

The **foreign exchange loss** resulted from the translation of foreign currency denominated transactions to U.S. dollars.

Capital Program—Corporate and Brazil

Capital expenditures in Corporate and Brazil during the year ended December 31, 2011 were $52.6 million and included $28 million for the acquisition of a 70% participating interest in four blocks in the onshore Recôncavo Basin of Brazil, drilling of two exploration and one delineation wells, seismic and site preparation expenses and the cost of drilling materials for future wells.

We hold interests in four blocks in the onshore Recôncavo Basin and one block in the offshore Camamu-Almada Basin. The significant elements of our 2011 Capital Program in Brazil were as follows:

Blocks 129, 142, 155 and 224, Recôncavo Basin
(70% working interest and operator)

On June 15, 2011, we received final approvals for the acquisition of a 70% participating interest in Blocks 129, 142, 155 and 224 in the onshore Recôncavo Basin of Brazil and also became the operator of these blocks effective from that date. With the exception of one block which has a producing well, the remaining blocks are unproved properties. First production contribution from the producing block was recorded in June 2011.

We drilled two gross exploration wells, 1-GTE-01-BA and 1-GTE-02-BA, on Blocks 142 and 129, respectively and an appraisal well, 3-GTE-03-BA on Block 155, was spud in December 2011. Drilling of the 1-GTE-01-BA vertical pilot exploration well was completed in November 2011. Core samples were acquired from the prospective reservoir section of the pilot well and we plan to drill a horizontal sidetrack in mid-2012 to test the productivity of light oil sandstone reservoir targets. Drilling of the 1-GTE-02-BA exploration well is suspended while plans are finalized for drilling a horizontal leg in mid-2012. Drilling of the 3-GTE-03-BA delineation well began on December 1, 2011 to further develop the existing discovery on Block REC-T-155. Oil bearing reservoir intervals were encountered and we are moving forward with plans to complete and place this well on production.

We also acquired 35 square kilometers of 3D seismic on Block 155.

BM-CAL-7 Block, Camamu Basin (10% non-operated working interest; Petrobras 60% is the operator; Statoil 30%;)
We purchased 1,366 square kilometers of an existing 3D seismic survey for the evaluation of the block.

BM-CAL-10 Block, Camamu Basin (15% non-operated working interest; Statoil 45% is the operator; Petrobras 40%)
The ANP has announced the 1-STAT-7-BAS exploration well drilling has been completed after reaching a total measured depth of 3,651 meters. Contractually, we are restricted from discussing the well results. In accordance with the terms of the farmout agreement, we gave notice to Statoil that we will not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farmout agreement has terminated and we will not receive any interest in Block BM-CAL-10.

Capital expenditures in the comparative periods of 2010 of $22.6 million included a $8.0 million refundable deposit on the Brazil farm-in, $4.4 million non-refundable expenditures relating to capital commitments on the Brazil farm-in, and $2.0 million of general corporate assets.

Capital expenditures in the year ended December 31, 2009 of $0.6 million related to leasehold improvements and the purchase of office furniture and equipment for our headquarters in Calgary.

Outlook—Corporate and Brazil

The 2012 capital program in Brazil is $68 million with $62 million allocated to drilling, $3 million to facilities and pipelines and $3 million to G&G expenditures. We plan to drill two gross exploration pilot wells onshore which will be followed by drilling three horizontal sidetracks, including one from the recently completed 1-GTE-01-BA pilot hole and one gross development well. Including the cost of the recent offshore well on Block BM-CAL-10, the exploration portion of the budget is expected to be $62 million. The 2012 development program in Brazil includes one gross development well. Our development drilling program will focus on Recôncavo Basin. Approximately $3 million is intended to be dedicated to pipelines and facilities and an additional $3 million for G&G work. Planned facilities work includes additional tankage, pipelines and gas facilities on Block 155.

Liquidity and Capital Resources

At December 31, 2011, we had cash and cash equivalents of $351.7 million compared with $355.4 million at December 31, 2010, and $270.8 million at December 31, 2009.

We believe that our cash position and cash generated from operations will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for at least the next 12 months. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc, in interest earning current accounts or are invested in U.S or Canadian government backed federal, provincial or state securities with the highest credit ratings and short term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

We believe that we have sufficient available cash and cash flow from operations to cover our expected funding needs on both a short-term and long-term basis. If the need were to arise, we believe that we could access short-term debt markets, to fund our short-term requirements and to ensure near-term liquidity. We regularly monitor the credit and financial markets and, in the future, may issue long-term debt to further improve our liquidity and capital resources. Our long-term financing strategy is to maintain the ability to access debt markets to accommodate our long term growth strategy.

At December 31, 2011, 91% of our cash and cash equivalents was held by our foreign subsidiaries. This balance is not available to fund domestic operations unless funds are repatriated. We do not intend to repatriate funds, but if we did we would have to accrue and pay taxes.

Effective July 30, 2010, we established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve based facility has a maximum borrowing base of up to $100 million and is supported by the present value of our Colombian petroleum reserves of two of our subsidiaries with operating branches in Colombia—Gran Tierra Energy Colombia Ltd. and Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. At December 31, 2011, we had not drawn down any amounts under this facility.

As part of the acquisition of Petrolifera, we assumed a reserve backed credit facility with outstanding balance as at the acquisition date of $31.3 million. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries.

Cash Flows

During the year ended December 31, 2011, our cash and cash equivalents decreased by $3.7 million as a result of cash used in investing activities of $311.7 million and cash used in financing activities of $49.0 million, partially offset by cash provided by operating activities of $356.9 million.

Net cash provided by operating activities in 2011 was positively affected by increased production and improved oil prices and a decrease in non-cash working capital. These positive contributions were partially offset by increased operating and G&A expenses to support the expanded operations. Cash outflows from investing activities in 2011 included capital expenditures of $333.2 million and an increase in restricted cash of $10.2 million, partially offset by proceeds on sale of asset-backed commercial paper ("ABCP") of $22.7 million and $7.7 million cash acquired through the Petrolifera acquisition. Cash outflows from financing activities in 2011 included repayment of $31.3 million of bank debt and $22.8 million of an ABCP line of credit, partially offset by $5.1 million related to proceeds from issuance of common shares. Both the bank debt and the ABCP line of credit were acquired through the Petrolifera acquisition.

During the year ended December 31, 2010, our cash and cash equivalents increased by $84.6 million as cash inflows from operations of $203.8 million and proceeds from issuance of common shares of $24.8 million more than offset cash outflows for capital expenditures of $152.3 million. Net cash provided by operating activities was positively affected by the increases in oil production and prices, offset by higher receivables related to oil sales.

During the year ended December 31, 2009, our cash and cash equivalents increased by $94.0 million as cash inflows from operations of $165.5 million and proceeds from issuance of common shares of $4.9 million more than offset cash outflows for capital expenditures of $80.9 million. Net cash provided by operating activities in 2009 was affected by the significant increase in oil production partially offset by the decrease in oil prices and increase in receivables related to oil sales.

Off-Balance Sheet Arrangements

As at December 31, 2011, 2010 and 2009 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2011.

					As at December 31, 2011
		Payments Due in Period			
Contractual Obligations *(Thousands of U.S. Dollars)*	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
Oil transportation services	$ 38,059	$ 13,280	$ 8,029	$ 7,100	$ 9,650
Drilling and geological and geophysical	41,034	39,550	1,484	-	-
Completion	23,053	15,273	7,780	-	-
Facility construction	32,195	15,673	16,522	-	-
Operating leases	7,798	4,567	2,779	452	-
Software and telecommunication	3,196	2,587	609	-	-
Consulting	897	843	54	-	-
Total	$ 146,232	$ 91,773	$ 37,257	$ 7,552	$ 9,650

At December 31, 2011, we had also provided promissory notes totalling $20.7 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contractual commitments have increased from December 31, 2010 mainly as a result of new pipeline transportation contract commitments and compressor and other operating equipment leases assumed upon the acquisition of Petrolifera.

Related Party Transactions

On January 12, 2011, we entered into an agreement to sublease office space to a company of which our President and Chief Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $4,500 for operating and other expenses, the terms are consistent with market conditions in the Calgary, Alberta, Canada real estate market.

On August 3, 2010, we entered into a contract related to the Peru drilling program with a company of which one of our directors is a shareholder and director. For the year ended December 31, 2011, $2.8 million was capitalized (December 31, 2010: $0.8 million)

On February 1, 2009, we entered into a sublease for office space with a company, of which one of our directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses. The terms of the sublease were consistent with market conditions in the Calgary, Alberta, Canada real estate market.

Subsequent Events

On February 17, 2012, in accordance with the terms of a farmout agreement, we gave notice to Statoil that we will not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farmout agreement has terminated and we will not receive any interest in the block. Pursuant to the farmout agreement, we are obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to the well that was drilled during the term of the farmout agreement. We expect to make that payment in the approximate amount of $26 million in March 2012.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.

On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material. The areas of accounting and the associated critical estimates and assumptions made are discussed below.

Full Cost Method of Accounting, Proved Reserves, DD&A and Impairments of Oil and Gas Properties

We follow the full cost method of accounting for our oil and natural gas properties in accordance with U.S. Securities and Exchange Commission ("SEC") Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements.

Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations, and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The ceiling test limits pooled costs to the aggregate of the discounted estimated after-tax future net revenues from proved oil and gas properties, plus the lower of cost or estimated fair value of unproved properties less any associated tax effects.

If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expenses in future periods. The ceiling limitation is imposed separately for each country in which we have oil and gas properties. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Our estimates of proved oil and gas reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the amount and timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the United States as prescribed by the Society of Petroleum Engineers. Reserve estimates are audited at least annually by independent qualified reserves consultants.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2011 ceiling tests were based on wellhead prices as of the first day of each month within that twelve month period of $95.20 for Colombia, $54.26 for Argentina and $97.07 for Brazil.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. Historical oil and gas prices for any particular 12-month period, can be either higher or lower than our price forecast. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Our Reserves Committee oversees the annual review of our oil and gas reserves and related disclosures. The Board meets with management periodically to review the reserves process, results and related disclosures and appoints and meets with the independent reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

We assessed our oil and gas properties for impairment as at December 31, 2011 and found no impairment write-down was required based on our calculations for our Colombia and Brazil cost centers. As a result of assessing oil and gas properties in our Peru and Argentina cost centers, ceiling test impairment losses of $42.0 million and $25.7 million respectively were recorded. The 2011 impairment charge in the Peru cost center related to seismic and drilling costs from dry wells on two blocks which were relinquished. The 2011 impairment charge in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentine proved reserves and a decrease in reserve volumes. We assessed our oil and gas properties for impairment as at December 31, 2010 and found no impairment write-down was required based on our assumptions for our Colombia cost center. A ceiling test impairment loss of $23.6 million was recorded in our Argentina cost centre in 2010 as a result of the abandonment of the GTE.St.VMor-2001 sidetrack operations, an increase in estimated future operating costs to produce our remaining Argentine proved reserves and a decrease in reserve volumes. We assessed our oil and gas properties for impairment as at December 31, 2009 and found that an impairment write-down of $1.9 million was required for our Argentina cost center.

Because of the volatile nature of oil and gas prices, it is not possible to predict the timing or magnitude of full cost writedowns. In addition, due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test previously discussed. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expenses.

Unproved properties

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. Unproved properties, the costs of which are individually significant, are assessed individually by considering seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, these properties are grouped for purposes of assessing impairment. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, geological and geophysical evaluations, the assignment of proved reserves, availability of capital, and other factors. For prospects where a reserve base has not yet been established, the impairment is charged to earnings.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future asset retirement obligations ("ARO") requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record ARO in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities. In arriving at amounts recorded, we make numerous assumptions and judgments with respect to the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements, inflation factors, credit-adjusted risk-free discount rates and changes in legal, regulatory, environmental and political environments. Because costs typically extend many years into the future, estimating future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

Allocation of Consideration Transferred in Business Combinations

The acquisition of Petrolifera was accounted for using the purchase method, with Gran Tierra being the acquirer, whereby the Petrolifera assets acquired and liabilities assumed were recorded at their fair values at the acquisition date with the excess of the fair values of the net assets acquired over the consideration transferred recorded as a gain on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the acquired company as well as the future production and development costs and future oil and gas prices.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both oil and gas properties and non-oil and gas properties, the lower future net income will be as a result of higher future DD&A expenses. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling write down in the event that future oil and gas prices drop below the price forecast used to originally determine fair value.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed and we test goodwill for impairment at least annually. The impairment test requires allocating goodwill and certain other assets and liabilities to a level of reporting referred to as a reporting unit. We compare the fair value of each reporting unit to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, we would write down the goodwill to the implied fair value of the goodwill through a charge to expense. The most significant judgments involved in estimating the fair values of our reporting units relate to the valuation of our property and equipment. Because quoted market prices are not available for our reporting units, fair values of reporting units are based upon estimated future cash flows of the reporting unit.

A lower goodwill value decreases the likelihood of an impairment charge. However, unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

The goodwill on our balance sheet resulted from the Solana and Argosy Energy International L.P. Argosy acquisitions, and relates entirely to the Colombia reporting unit. This reporting unit is not at risk of failing the

"Step 1" goodwill impairment test under GAAP. The calculated fair value of the Colombian reporting unit is significantly in excess of its carrying value.

Differences in the our actual future cash flows, operating results, growth rates, capital expenditures, cost of capital and discount rates as compared with the estimates utilized for the purpose of calculating the fair value of each business unit, as well as a decline in our stock price and related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

Income Taxes

We follow the liability method of accounting for income taxes whereby we recognize deferred income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

Our effective tax rate is based on pre-tax income and the tax rates applicable to that income in the various jurisdictions in which we operate. An estimated effective tax rate for the year is applied to our quarterly operating results. In the event that there is a significant unusual or discrete item recognized, or expected to be recognized, in our quarterly operating results, the tax attributable to that item would be separately calculated and recorded at the same time as the unusual or discrete item. We consider the resolution of prior-year tax matters to be such items. Significant judgment is required in determining our effective tax rate and in evaluating our tax positions. We establish reserves when it is more likely than not that we will not realize the full tax benefit of the position. We adjust these reserves in light of changing facts and circumstances.

We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts.

Legal and Other Contingencies

A provision for legal and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. Management closely monitors known and potential legal and other contingencies and periodically determines when we should record losses for these items based on information available to us.

Stock-Based Compensation

Our stock-based compensation cost is measured based on the fair value of the award on the grant date. The compensation cost is recognized net of estimated forfeitures over the requisite service period. GAAP requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

We utilize the Black-Scholes option pricing model to measure the fair value of all of our stock options. The use of such models requires substantial judgment with respect to expected life, volatility, expected returns and other factors. Expected volatility is based on the historical volatility of our common stock. We use historical experience for exercises to determine expected life. We are responsible for determining the assumptions used in estimating the fair value of our share based payment awards.

New Accounting Pronouncements

We have reviewed all recently issued, but not yet adopted, accounting standard updates in order to determine their effects, if any, on our consolidated financial statements. Based on that review, we believe that the implementation of these standards will not materially impact our consolidated financial position, operating results, cash flows, or disclosure requirements.

Quantitative and Qualitative Disclosure about Market Risk

Our principal market risk relates to oil prices. Most of our revenues are from oil sales at prices which are defined by contract relative to WTI and adjusted for transportation and quality each month. In Argentina, a further discount factor which is related to a tax on oil exports establishes a common pricing mechanism for all oil produced in the country, regardless of its destination.

Foreign currency risk is a factor for our company but is ameliorated to a large degree by the nature of expenditures and revenues in the countries where we operate. We have not engaged in any formal hedging activity with regard to foreign currency risk. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. price of WTI or Brent oil.

In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars. The majority of our capital expenditures in Peru are in U.S. dollars. In Argentina and Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of our capital expenditures within Argentina and Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. The majority of local office expenditures in all locations are in local currency. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, unrealized foreign exchange gains and losses result from the fluctuation of the U.S. dollar to the Colombian peso due to our deferred tax liability, a monetary liability, which is mainly denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

We consider our exposure to interest rate risk to be immaterial. Our interest rate exposures primarily relate to our investment portfolio. Our investment objectives are focused on preservation of principal and liquidity. By policy, we manage our exposure to market risks by limiting investments to high quality bank issues at overnight rates, or government securities of the United States or Canadian federal governments such as Guaranteed Investment Certificates or Treasury Bills. A 10% change in interest rates would not have a material effect on the value of our investment portfolio. We do not hold any of these investments for trading purposes. We do not hold equity investments, and we have no debt.

Financial Statements and Supplementary Data

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.:

We have audited the accompanying consolidated financial statements of Gran Tierra Energy Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, and the consolidated statements of operations and retained earnings, consolidated statements of shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2011, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and its subsidiaries as at December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011 in accordance with accounting principles generally accepted in the United States of America.

Other Matters

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2012

Consolidated Statements of Operations and Retained Earnings

For the Years Ended December 31, 2011, 2010 and 2009

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)	2011	2010	2009
			As at December 31,
REVENUE AND OTHER INCOME			
Oil and natural gas sales	$ 596,191	$ 373,286	$ 262,629
Interest income	1,216	1,174	1,087
	597,407	374,460	263,716
EXPENSES			
Operating	86,497	59,446	40,784
Depletion, depreciation, accretion and impairment (Note 6)	231,235	163,573	135,863
General and administrative	60,389	40,241	28,787
Equity tax (Note 9)	8,271	–	–
Financial instruments (gain) loss (Notes 3 and 12)	(1,522)	(44)	190
Gain on acquisition (Note 3)	(21,699)	–	–
Foreign exchange (gain) loss	(11)	16,838	19,797
	363,160	280,054	225,421
INCOME BEFORE INCOME TAXES	234,247	94,406	38,295
Income tax expense (Note 9)	(107,330)	(57,234)	(24,354)
NET INCOME AND COMPREHENSIVE INCOME	126,917	37,172	13,941
RETAINED EARNINGS, BEGINNING OF YEAR	58,097	20,925	6,984
RETAINED EARNINGS, END OF YEAR	$ 185,014	$ 58,097	$ 20,925
NET INCOME PER SHARE—BASIC	$ 0.46	$ 0.15	$ 0.06
NET INCOME PER SHARE—DILUTED	$ 0.45	$ 0.14	$ 0.05
WEIGHTED AVERAGE SHARES OUTSTANDING—BASIC (Note 7)	273,491,564	253,697,076	241,258,568
WEIGHTED AVERAGE SHARES OUTSTANDING—DILUTED (Note 7)	281,287,002	264,304,831	253,590,103

(See notes to the consolidated financial statements)

Consolidated Balance Sheets

As at December 31, 2011 and 2010

		As at December 31,		
(Thousands of U.S. Dollars)		2011		2010
ASSETS				
Current Assets				
Cash and cash equivalents	$	351,685	$	355,428
Restricted cash		1,655		250
Accounts receivable (Note 5)		69,362		43,035
Inventory (Note 5)		7,116		5,669
Taxes receivable		21,485		6,974
Prepaids		3,597		1,940
Deferred tax assets (Note 9)		3,029		4,852
Total Current Assets		457,929		418,148
Oil and Gas Properties (using the full cost method of accounting)				
Proved		618,982		442,404
Unproved		417,868		278,753
Total Oil and Gas Properties		1,036,850		721,157
Other capital assets		7,992		5,867
Total Property, Plant and Equipment (Note 6)		1,044,842		727,024
Other Long Term Assets				
Restricted cash		13,227		1,190
Deferred tax assets (Note 9)		4,747		-
Other long term assets		3,454		311
Goodwill (Note 2)		102,581		102,581
Total Other Long Term Assets		124,009		104,082
Total Assets	$	1,626,780	$	1,249,254
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable (Note 10)	$	82,189	$	76,023
Accrued liabilities (Note 10)		66,832		32,120
Taxes payable		95,482		43,832
Asset retirement obligation (Note 8)		326		338
Total Current Liabilities		244,829		152,313
Long Term Liabilities				
Deferred tax liability (Note 9)		186,799		204,570
Equity tax payable (Note 9)		6,484		-
Asset retirement obligation (Note 8)		12,343		4,469
Other long term liabilities		2,007		1,036
Total Long Term Liabilities		207,633		210,075
Commitments and Contingencies (Note 11)				
Subsequent Events (Note 15)				
Shareholders' Equity				
Common shares (Note 7) (262,304,249 and 240,440,830 common shares and 16,323,819 and 17,681,123 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2011 and 2010, respectively)		7,510		4,797
Additional paid in capital		980,014		821,781
Warrants (Note 7)		1,780		2,191
Retained earnings		185,014		58,097
Total Shareholders' Equity		1,174,318		886,866
Total Liabilities and Shareholders' Equity	$	1,626,780	$	1,249,254

(See notes to the consolidated financial statements)

Consolidated Statements of Cash Flows

For the Years Ended December 31, 2011, 2010 and 2009

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2011	2010	2009
Operating Activities			
Net income	$ 126,917	$ 37,172	$ 13,941
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, accretion and impairment (Note 6)	231,235	163,573	135,863
Deferred taxes (Note 9)	(29,222)	(20,090)	(15,355)
Stock-based compensation (Note 7)	12,767	8,025	5,309
(Gain) loss on financial instruments (Notes 3 and 12)	(1,354)	(44)	277
Unrealized foreign exchange (gain) loss	(1,695)	14,786	19,496
Settlement of asset retirement obligation (Note 8)	(345)	(286)	(52)
Equity tax	2,442	–	–
Gain on acquisition (Note 3)	(21,699)	–	–
Net changes in non-cash working capital			
Accounts receivable	(15,627)	(5,323)	(27,926)
Inventory	(548)	(1,221)	(1,849)
Prepaids	(1,321)	(120)	(717)
Accounts payable and accrued liabilities	19,918	(3,212)	36,875
Taxes receivable and payable	35,422	10,522	(409)
Net cash provided by operating activities	356,890	203,782	165,453
Investing Activities			
Restricted cash	(10,197)	352	(1,792)
Additions to property, plant and equipment	(333,194)	(152,299)	(80,932)
Proceeds from disposition of oil and gas properties (Note 6)	4,450	7,986	5,400
Cash acquired on acquisition (Note 3)	7,747	–	–
Proceeds on sale of asset-backed commercial paper (Note 3)	22,679	–	–
Long term assets and liabilities	(3,138)	36	968
Net cash used in investing activities	(311,653)	(143,925)	(76,356)
Financing Activities			
Settlement of bank debt (Notes 3 and 13)	(54,103)	–	–
Proceeds from issuance of common shares	5,123	24,785	4,935
Net cash (used in) provided by financing activities	(48,980)	24,785	4,935
Net (decrease) increase in cash and cash equivalents	(3,743)	84,642	94,032
Cash and cash equivalents, beginning of year	355,428	270,786	176,754
Cash and cash equivalents, end of year	$ 351,685	$ 355,428	$ 270,786
Cash	$ 172,645	$ 272,151	$ 182,197
Term deposits	179,040	83,277	88,589
Cash and cash equivalents, end of year	$ 351,685	$ 355,428	$ 270,786
Supplemental cash flow disclosures:			
Cash paid for interest	$ 1,604	$ –	$ –
Cash paid for taxes	$ 67,053	$ 49,088	$ 31,527
Non-cash investing activities:			
Non-cash working capital related to property, plant and equipment	$ 43,333	$ 48,640	$ 17,972

(See notes to the consolidated financial statements)

Consolidated Statements of Shareholders' Equity

For the Years Ended December 31, 2011, 2010 and 2009

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2011**	2010	2009
Share Capital			
Balance, beginning of year	**$ 4,797**	$ 1,431	$ 226
Issue of common shares	**2,713**	3,366	1,205
Balance, end of year	**7,510**	4,797	1,431
Additional Paid in Capital			
Balance, beginning of year	**821,781**	766,963	754,832
Issue of common shares	**142,109**	19,119	2,650
Exercise of warrants (Note 7)	**411**	24,916	2,777
Exercise of stock options (Note 7)	**1,990**	2,300	1,080
Stock-based compensation expense (Note 7)	**13,723**	8,483	5,624
Balance, end of year	**980,014**	821,781	766,963
Warrants			
Balance, beginning of year	**2,191**	27,107	29,884
Exercise of warrants (Note 7)	**(411)**	(24,916)	(2,777)
Balance, end of year	**1,780**	2,191	27,107
Retained Earnings			
Balance, beginning of year	**58,097**	20,925	6,984
Net income	**126,917**	37,172	13,941
Balance, end of year	**185,014**	58,097	20,925
Total Shareholders' Equity	**$ 1,174,318**	$ 886,866	$ 816,426

(See notes to the consolidated financial statements)

Notes to the Consolidated Financial Statements

For the Years Ended December 31, 2011, 2010 and 2009.
Expressed in U.S. Dollars, unless otherwise stated.

1. Description of Business

Gran Tierra Energy Inc., a Nevada corporation (the "Company" or "Gran Tierra"), is a publicly traded oil and gas company engaged in acquisition, exploration, development and production of oil and natural gas properties. The Company's principal business activities are in Colombia, Argentina, Peru and Brazil.

2. Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP"). The Company believes that the information and disclosures presented are adequate to ensure the information presented is not misleading.

Significant accounting policies are:

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment ("DD&A"); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to amortization to the amortization base; asset retirement obligations; determining the value of the consideration transferred and the net identifiable assets acquired and liabilities assumed in connection with business combinations and determining goodwill; income taxes; legal and other contingencies; and stock-based compensation. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates.

Cash and cash equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted cash

Restricted cash comprises cash and cash equivalents pledged to secure letters of credit. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Restricted cash is classified between current and long term assets based on the expiration dates of the letters of credit.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred. The allowance for doubtful receivables was nil at December 31, 2011 and 2010.

Inventory

Inventory consists of oil in tanks and supplies and is valued at the lower of cost or market value. The cost of inventory is determined using the weighted average method. Oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities.

Income taxes

Income taxes are recognized using the liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the consolidated financial statement carrying amounts of existing assets and liabilities and their respective tax base, and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. Valuation allowances are provided if, after considering available evidence, it is not more likely than not that some or all of the deferred tax assets will be realized.

The tax benefit from an uncertain tax position is recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company presumes that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The Company recognizes potential penalties and interest related to unrecognized tax benefits as a component of income tax expense.

Oil and gas properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as defined by the Securities and Exchange Commission ("SEC"). Under this method, the Company capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits and other internal costs directly attributable to these activities. Costs associated with production and general corporate activities; however, are expensed as incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Separate cost centers are maintained for each country in which the Company incurs costs.

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion The costs of unproved properties are excluded from the amortization until the properties are evaluated. The cost of exploratory dry wells is transferred to proved properties, and thus subject to amortization, immediately upon determination that a well is dry in those countries where proved reserves exist.

The Company performs a ceiling test calculation each quarter in accordance with SEC Regulation S-X Rule 4-10. In performing its quarterly ceiling test, the Company limits, on a country-by-country basis, the capitalized costs of proved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to net income. Any such write-down will reduce earnings in the period of occurrence and results in a lower DD&A rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company implemented the SEC final rule "Modernization of Oil and Gas Reporting" at December 31, 2009 and calculates future net cash flows by applying the average of prices in effect on the first day of the month for the preceding 12 month period, adjusted for location and quality differentials. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts.

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. For prospects where a reserve base has not yet been established, the impairment is charged to earnings.

In exploration areas, related geological and geophysical ("G&G") costs are capitalized in unproved property and evaluated as part of the total capitalized costs associated with a property. G&G costs related to development projects are recorded in proved properties and therefore subject to amortization as incurred.

Gains and losses on the sale or other disposition of oil and natural gas properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

Asset retirement obligation

The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to the related oil and gas properties. The fair value of asset retirement obligations are measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets. The accretion of the asset retirement obligation and amortization of the asset retirement cost are included in DD&A. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Other capital assets

Other capital assets, including additions and replacements, are recorded at cost upon acquisition and include furniture, fixtures and leasehold improvement, computer equipment and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed and is tested for impairment at least annually unless business events indicate an impairment test is required more frequently. The impairment test requires allocating goodwill and certain other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared with the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for the Company's reporting units, the fair values of the reporting units are estimated based upon estimated future cash flows of the reporting unit.

The Company recorded $87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("Solana") in 2008 and $15.0 million of goodwill in relation to the Argosy Energy International L.P. ("Argosy") acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed annual impairment tests of goodwill at December 31, 2011 and 2010. Based on these assessments, no impairment of goodwill was identified.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when title passes to the customer and when collection of the revenue is reasonably assured. For the Company's Colombian operations, Gran Tierra's customers take title when the oil is transferred to their pipeline. In Argentina, Gran Tierra transports oil from the field to the customer's refinery or the oil terminal by pipeline or truck, where title is transferred. For the Company's gas sales in Argentina, Gran Tierra's customers take title when the gas is transferred to their pipeline. In Brazil, Gran Tierra transports product from the field to the customer's station by truck, where title is transferred. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company follows the fair-value based method of accounting for stock options granted to directors, officers and employees. Compensation expense for options granted is based on the estimated fair value, using the Black-Scholes option pricing model, at the time of grant and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures related to vested awards. The Company uses historical data to estimate option exercises, expected term and employee departure behavior used in the Black-Scholes option pricing model. Expected volatilities used in the fair value estimate are based on historical volatility of the Company's stock. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant. Stock-based compensation expense is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or general and administrative ("G&A") expenses, as appropriate.

Warrants

The Company issued warrants ("Replacement Warrants") in connection with its acquisition of Petrolifera Petroleum Limited ("Petrolifera") in March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011. These warrants were derivative financial instruments and were recognized at fair value in the consolidated balance sheet as a current liability and as part of the consideration paid for the acquisition (Note 12). In connection with the acquisition of Solana in November 2008, the Company recorded the fair value of warrants assumed of $23.6 million as part of the consideration paid for the acquisition. The Company determines the fair value of warrants issued using the Black-Scholes option pricing model.

Foreign currency translation

The functional currency of the Company, including its subsidiaries, is the United States dollar. Monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date and non-monetary items are translated at historical exchange rates. Revenue and expense items are translated in a manner that produces substantially the same reporting currency amounts that would have resulted had the underlying transactions been translated on the dates they occurred. Depreciation or amortization of assets is translated at the historical exchange rates similar to the assets to which they relate.

Gains and losses resulting from foreign currency transactions, which are transactions denominated in a currency other than the entity's functional currency, are recognized in net income.

Net income per share

Basic net income per share is calculated by dividing net income attributable to common shareholders by the weighted average number of common shares issued and outstanding during each period. Diluted net income per share is calculated by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect. This method assumes that all common share equivalents have been exercised at the beginning of the period (or at the time of issuance, if later), and that the funds obtained thereby were used to purchase common shares of the Company at the average trading price of common shares during the period.

Adopted accounting pronouncements

Stock Compensation

In April 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2010-13, "Compensation–Stock Compensation (Topic 718)." The update clarifies that an employee share-based payment award with an exercise price denominated in the currency of a market in which a substantial portion of the entity's equity securities trades should not be considered to contain a condition that is not a market, performance, or service condition. Therefore, an entity would not classify such an award as a liability if it otherwise qualifies as equity. This ASU was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2010. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows.

Business Combinations

In December 2010, the FASB issued ASU 2010-29, "Business Combinations (Topic 850), Disclosures of Supplementary Pro Forma Information for Business Combinations." The update is intended to conform reporting of pro forma revenue and earnings for material business combinations included in the notes to the financial statements and expand disclosure of non-recurring adjustments that are directly attributable to the business combination. The pro forma revenue and earnings of the combined entity are presented as if the acquisition had occurred as of the beginning of the annual reporting period. If comparatives are presented, the pro forma disclosures for both periods presented should be reported as if the acquisition had occurred as of the beginning of the comparable prior annual reporting period only. This ASU was effective for business combinations for which the acquisition date was on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The disclosure requirements of this ASU have been adopted by the Company.

Recently issued accounting pronouncements

Goodwill

In September 2011, the FASB issued ASU 2011-08, "Intangibles—Goodwill and Other (Topic 350)." The update is intended to simplify how entities test goodwill for impairment. The update permits entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. This ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2011.The implementation of this update is not expected to materially impact the Company's consolidated financial position, results of operations or cash flows.

Disclosure about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet—Disclosure about Offsetting Assets and Liabilities (Topic 210)." The update requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. This ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after January 1, 2013. The implementation of this update is not expected to materially impact the Company's disclosure.

3. Business Combination

On March 18, 2011 (the "Acquisition Date"), Gran Tierra completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera, a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011 (the "Arrangement"). Petrolifera is a Calgary based oil, natural gas and natural gas liquids exploration, development and production company active in Argentina, Colombia and Peru. The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petrolifera shareholders on March 17, 2011 and by the Court of Queen's Bench of Alberta on March 18, 2011.

Under the Arrangement, Petrolifera shareholders received, for each Petrolifera share held, 0.1241 of a share of Gran Tierra common stock, and Petrolifera warrant holders received, for each Petrolifera warrant held, 0.1241 of a Replacement Warrant to purchase a share of Gran Tierra common stock at an exercise price of $9.67 Canadian ("CDN") dollars per share. The Replacement Warrants expired unexercised on August 28, 2011.

Gran Tierra acquired all the issued and outstanding Petrolifera shares and warrants through the issuance of 18,075,247 Gran Tierra common shares, par value $0.001, and 4,125,036 Replacement Warrants. Upon completion of the transaction on the Acquisition Date, Petrolifera became an indirect wholly-owned subsidiary of Gran Tierra. On a diluted basis, upon the closing of the Arrangement, Petrolifera and Gran Tierra security holders owned approximately 6.6% and 93.4% of the Company, respectively, immediately following the transaction. The total consideration for the transaction was approximately $143 million.

The fair value of Gran Tierra's common shares was determined as the closing price of the common shares of Gran Tierra as at the Acquisition Date.

The fair value of the Replacement Warrants was estimated on the Acquisition Date using the Black-Scholes option pricing model with the following assumptions:

Exercise price (CDN dollars per warrant)	$	9.67
Risk-free interest rate		1.3%
Expected life		0.45 Years
Volatility		44%
Expected annual dividend per share		Nil
Estimated fair value per warrant (CDN dollars)	$	0.32

The financial instruments gain reflected in the consolidated statement of operations for the year ended December 31, 2011, includes a $1.3 million gain arising from the fair value of the expired Replacement Warrants.

The acquisition is accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed are recognized at their fair values as at the Acquisition Date and the results of Petrolifera have been consolidated with those of Gran Tierra from that date.

The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)		
Consideration Transferred:		
Common shares issued net of share issue costs	$	141,690
Replacement warrants		1,354
	$	143,044
Allocation of Consideration Transferred:		
Oil and gas properties		
Proved	$	58,457
Unproved		161,278
Other long term assets		4,417
Net working capital (including cash acquired of $7.7 million and accounts receivable of $6.4 million)		(17,223)
Asset retirement obligation		(4,901)
Bank debt		(22,853)
Other long term liabilities		(14,432)
Gain on acquisition		(21,699)
	$	143,044

As shown above, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized a gain of $21.7 million, which is reported as "Gain on acquisition", in the consolidated statement of operations. The gain reflects the impact on Petrolifera's pre-acquisition market value of a lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

As part of the assets acquired and included in the net working capital in the allocation of the consideration transferred, the Company assigned $22.5 million in fair value to investments in notes that Petrolifera received in exchange for asset-backed commercial paper ("ABCP") with a face value of $31.3 million. On March 28, 2011, these notes were sold to an unrelated party for proceeds of $22.7 million after the associated line of credit was settled. When combined with the gain arising on the expiry of the Replacement Warrants, the financial instruments gain for the year ended December 31, 2011 was $1.5 million.

The associated ABCP line of credit that Gran Tierra assumed was with a Canadian Chartered Bank, to a maximum of CDN$23.2 million with an initial expiry in April 2012. Gran Tierra settled this line of credit immediately after the completion of the acquisition of Petrolifera for the face value of CDN$22.5 million in borrowings plus accrued interest.

Also upon the acquisition of Petrolifera, Gran Tierra assumed a second line of credit agreement ("Second ABCP line of credit") with the same Canadian chartered bank to a maximum of CDN$5.0 million, which was fully drawn as at the Acquisition Date. This Second ABCP line of credit, which expired on April 8, 2011, was secured by ineligible master asset vehicles Classes 1 & 2 ("MAV IA 1 & 2") notes with a face value of $6.6 million. Gran Tierra retained the option to settle the Second ABCP line of credit of CDN$5.0 million through delivery to the lender of the MAV IA 1 & 2 notes. Subsequent to the acquisition, Gran Tierra elected to record this second line of credit at fair value and planned at that time to settle the debt through delivery of the MAV IA 1 & 2 notes. Accordingly, a value of $nil was recorded for the debt upon its acquisition. Gran Tierra settled such borrowings by delivery of the MAV IA 1 & 2 notes on April 8, 2011.

Gran Tierra also assumed a reserve-backed credit facility upon the Petrolifera acquisition with an outstanding balance of $31.3 million (Note 13). The amount outstanding under this credit facility was included as part of net working capital in the allocation of consideration transferred. This credit facility was repaid during August 2011, resulting in a total debt repayment of $54.1 million, when combined with the repayment of the CDN$22.5 million ABCP line of credit.

Pro forma results for the years ended December 31, 2011 and 2010 are shown below, as if the acquisition had occurred on January 1, 2010. Pro forma results are not indicative of actual results or future performance.

(Unaudited)	Year Ended December 31,	
(Thousands of U.S. Dollars except per share amounts)	2011	2010
Revenue and other income	$ 606,602	$ 427,137
Net income	$ 94,094	$ 7,557
Net income per share—basic	$ 0.34	$ 0.03
Net income per share—diluted	$ 0.33	$ 0.03

The supplemental pro forma earnings of Gran Tierra for the years ended December 31, 2011 and 2010 were adjusted to exclude $4.4 million of acquisition costs recorded in G&A expense and the $21.7 million gain on acquisition recognized in the 2011 results of Gran Tierra because they are not expected to have a continuing impact on Gran Tierra's results of operations. The consolidated statement of operations for the year ended December 31, 2011 includes oil and natural gas sales of $32.5 million from Petrolifera for the period subsequent to the Acquisition Date. Petrolifera incurred an after tax loss of $8.0 million in the period since the Acquisition Date.

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company's reportable segments are Colombia, Argentina and Peru based on a geographic organization. The Company's operations in Brazil are not a reportable segment because the level of activity in Brazil was not significant at December 31, 2011. During the three months ended March 31, 2011, Peru became a reportable segment due to the significance of its loss before income taxes compared with the consolidated results of operations. Prior year segmented disclosure has been conformed to this presentation with the Peru reportable segment's results and asset information disaggregated from the "All Other" category. The All Other category represents the Company's corporate activities and operations in Brazil.

The accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates segment performance based on income or loss before income taxes. The results of the Colombia, Argentina and Peru reportable segments include the operations of Petrolifera subsequent to March 18, 2011, the date of acquisition of Petrolifera (Note 3).

The following tables present information on the Company's reportable segments and other activities:

	Year Ended December 31, 2011				
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 543,999	$ 48,016	$ –	$ 4,176	$ 596,191
Interest income	492	66	140	518	1,216
DD&A expenses	141,133	45,506	42,035	2,561	231,235
DD&A—per unit of production	26.17	49.61	–	59.48	36.39
Income (loss) before income taxes	313,516	(32,635)	(46,249)	(385)	234,247
Segment capital expenditures[(1)]	$ 202,551	$ 36,289	$ 36,224	$ 52,583	$ 327,647

	Year Ended December 31, 2010				
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 359,302	$ 13,984	$ –	$ –	$ 373,286
Interest income	460	26	–	688	1,174
DD&A expenses	133,728	29,416	40	389	163,573
DD&A—per unit of production	26.80	103.56	–	–	31.02
Income (loss) before income taxes	142,486	(27,247)	(1,430)	(19,403)	94,406
Segment capital expenditures[(1)]	$ 105,482	$ 33,930	$ 15,029	$ 22,598	$ 177,039

	Year Ended December 31, 2009				
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 248,834	$ 13,795	$ –	$ –	$ 262,629
Interest income	466	127	–	494	1,087
DD&A expenses	127,213	8,339	–	311	135,863
DD&A—per unit of production	29.64	24.72	–	–	29.35
Income (loss) before income taxes	55,827	(4,230)	(396)	(12,906)	38,295
Segment capital expenditures[(1)]	$ 81,364	$ 4,532	$ 1,606	$ 622	$ 88,124

(1) Net of proceeds from the farm out of a 50% interest in the Santa Victoria Block and the sale of a blow-out preventer in Argentina in 2011 (see Note 6), the Garibay overriding royalty in Colombia in 2010 (see Note 6) and the Guachiria Blocks in Colombia in 2009 (see Note 6).

The Company's revenues are derived principally from uncollateralized sales to customers in the oil and natural gas industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions.

In 2011, the Company had one significant customer for its Colombian oil, Ecopetrol S.A. ("Ecopetrol"). Sales to Ecopetrol accounted for 87%, 96% and 94% of the Company's revenues in 2011, 2010 and 2009, respectively. In 2011 in Argentina, the Company had three significant customers, Refineria del Norte S.A ("Refiner"), Shell C.A.P.S.A. ("Shell") and YPF S.A. ("YPF"). Sales to Shell, Refiner and YPF accounted for 3%, 3% and 2% respectively of the Company's oil and natural gas sales in 2011. Sales to Refiner accounted for 4% and 6% of the Company's revenues in 2010 and 2009.

During the year ended December 31, 2011, interest expense of $1.6 million was recorded in G&A in Argentina (2010 and 2009—nil).

As at December 31, 2011

(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$ 816,396	$ 129,072	$ 34,305	$ 65,069	$ 1,044,842
Goodwill	102,581	-	-	-	102,581
Other assets	269,843	34,672	9,597	165,245	479,357
Total Assets	$ 1,188,820	$ 163,744	$ 43,902	$ 230,314	$ 1,626,780

As at December 31, 2010

(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$ 654,416	$ 29,031	$ 28,578	$ 14,999	$ 727,024
Goodwill	102,581	-	-	-	102,581
Other assets	155,798	15,220	18,575	230,056	419,649
Total Assets	$ 912,795	$ 44,251	$ 47,153	$ 245,055	$ 1,249,254

5. Accounts Receivable and Inventory

Accounts Receivable

(Thousands of U.S. Dollars)	As at December 31, 2011	2010
Trade	$ 45,922	$ 34,182
Other	23,440	8,853
Total	$ 69,362	$ 43,035

Inventory

Oil and supplies inventories at December 31, 2011 are $4.7 million and $2.4 million, respectively (2010—$3.6 million and $2.1 million, respectively).

6. Property, Plant and Equipment

As at December 31, 2011

(Thousands of U.S. Dollars)	Cost	Accumulated DD&A	Net Book Value
Oil and natural gas properties			
Proved	$ 1,181,503	$ (562,521)	$ 618,982
Unproved	417,868	–	417,868
	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	6,973	(4,002)	2,971
Computer equipment	8,443	(4,174)	4,269
Automobiles	1,295	(543)	752
Total Property, Plant and Equipment	$ 1,616,082	$ (571,240)	$ 1,044,842

As at December 31, 2010

(Thousands of U.S. Dollars)	Cost	Accumulated DD&A	Net Book Value
Oil and natural gas properties			
Proved	$ 777,262	$ (334,858)	$ 442,404
Unproved	278,753	–	278,753
	1,056,015	(334,858)	721,157
Furniture and fixtures and leasehold improvements	5,233	(2,831)	2,402
Computer equipment	5,521	(2,358)	3,163
Automobiles	779	(477)	302
Total Property, Plant and Equipment	$ 1,067,548	$ (340,524)	$ 727,024

On August 26, 2010, the Company entered into an agreement to acquire a 70% participating interest in four blocks in Brazil. With the exception of one block which has a producing well, the remaining blocks are unproved properties. The agreement was effective September 1, 2010, subject to regulatory approvals, and the transaction was completed on June 15, 2011. Purchase consideration was $40.1 million and was recorded in the All Other category of capital expenditures in 2011 and 2010. The 70% share of all benefits and costs with respect to the period between the effective date and the completion of the transaction were an adjustment to the consideration paid for the four blocks.

In March 2011, the Company recorded proceeds of $3.3 million from the farm out of a 50% interest in the Santa Victoria Block in Argentina to Apache Corporation. The Company also recorded $1.2 million from the sale of a blow-out preventer in Argentina in September 2011. In October 2010, the Company recorded proceeds of $6.4 million for the sale of an overriding interest in the Garibay Block in Colombia. In April 2009, Gran Tierra closed the sale of the Company's interests in the Guachiria Norte, Guachiria, and Guachiria Sur blocks in Colombia. Principal terms included consideration of $7.0 million comprising an initial cash payment of $4.0 million at closing, followed by 15 monthly installments of $200,000 each which began on June 1, 2009 and ended on August 3, 2010. The Company recorded proceeds of $1.6 million and $5.4 million in 2010 and 2009, respectively. Gran Tierra retained a 10% overriding royalty interest on the Guachiria Sur Block, which, in the event of a discovery, is designed to reimburse 200% of the Company's costs for previously acquired seismic data.

Depreciation, depletion and amortization was $163.5 million in 2011 (2010—$140 million; 2009—$134.0 million). In 2011, we recorded ceiling test impairment losses in the Company's Peru and Argentina cost centers of $42.0 million and $25.7 million, respectively. The 2011 impairment charge in the Peru cost center related to seismic and drilling costs from two blocks which were relinquished. The 2011 impairment charge in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentine proved reserves and a decrease in reserve volumes. In 2010, we recorded a $23.6 million ceiling test impairment loss in the Company's Argentina cost center as compared with a $1.9 million impairment loss for December 31, 2009. Of the 2010 impairment loss, $17.9 million related to the abandonment of the Valle Morado sidetrack operations and the remaining $5.7 million resulted from a decrease in reserves combined with higher forecasted operating costs to produce the remaining proved reserves. The 2009 impairment loss resulted from higher forecasted operating costs to produce the remaining proved reserves in Argentina.

The amounts capitalized in each of the Company's cost centers during the years ended December 31, 2011 and 2010 were as follows:

									Year Ended December 31, 2011	
(Thousands of U.S. Dollars)		**Colombia**		**Argentina**		**Peru**		**Brazil**		**Total**
Capitalized G&A, including stock-based compensation	$	7,996	$	3,189	$	1,183	$	1,985	$	14,353
Capitalized stock-based compensation	$	456	$	266	$	-	$	234	$	956

									Year Ended December 31, 2010	
(Thousands of U.S. Dollars)		Colombia		Argentina		Peru		Brazil		Total
Capitalized G&A, including stock-based compensation	$	4,127	$	1,171	$	287	$	-	$	5,585
Capitalized stock-based compensation	$	308	$	150	$	-	$	-	$	458

									Year Ended December 31, 2009	
(Thousands of U.S. Dollars)		Colombia		Argentina		Peru		Brazil		Total
Capitalized G&A, including stock-based compensation	$	1,600	$	600	$	30	$	-	$	2,230
Capitalized stock-based compensation	$	198	$	117	$	-	$	-	$	315

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. The Company had $274.8 million (December 31, 2010—$228.8 million) in unproved assets in Colombia, $57.0 million (December 31, 2010—$9.4 million) of unproved assets in Argentina and $33.7 million (December 31, 2010—$28.2 million) of unproved assets in Peru, and $52.4 million (December 31, 2010—$12.4 million) of unproved assets in Brazil for a total of $417.9 million (December 31, 2010—$278.8 million). These properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2011:

									Costs Incurred in
(Thousands of U.S. Dollars)		**2011**	2010		2009		Prior to 2009		Total
Acquisition costs—Colombia	$	76,346	–		–		159,045	$	235,391
Acquisition costs—Argentina		45,015	–		–		–		45,015
Acquisition costs—Peru		23,423	2,000		–		–		25,423
Acquisition costs—Brazil		22,891	12,395		–		–		35,286
Exploration costs—Colombia		19,233	12,427		3,311		487		35,458
Exploration costs—Argentina		181	683		163		229		1,256
Exploration costs—Peru		7,389	301		372		189		8,251
Exploration costs—Brazil		17,155	–		–		–		17,155
Development costs—Colombia		3,929	–		–		–		3,929
Development costs—Argentina		5,683	5,021		–				10,704
Total oil and natural gas properties not subject to depletion	$	221,245	32,827	$	3,846	$	159,950	$	417,868

7. Share Capital

The Company's authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as common stock, par value $0.001 per share, 25 million are designated as preferred stock, par value $0.001 per share, and two shares are designated as special voting stock, par value $0.001 per share. As at December 31, 2011, outstanding share capital consists of 262,304,249 common voting shares of the Company, 8,512,707 exchangeable shares of Gran Tierra Exchange Co., automatically exchangeable on November 14, 2013, and 7,811,112 exchangeable shares of Goldstrike Exchange Co., automatically exchangeable on November 10, 2012. The exchangeable shares of Gran Tierra Exchange Co, were issued upon acquisition of Solana. The exchangeable shares of Gran Tierra Goldstrike Inc. were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. Each exchangeable share is exchangeable into one common voting share of the Company. The holders of common stock are entitled to one vote for each share on all matters submitted to a stockholder vote and are entitled to share in all dividends that the Company's board of directors, in its discretion, declares from legally available funds. The holders of common stock have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the common stock. Holders of exchangeable shares have substantially the same rights as holders of common voting shares.

Warrants

At December 31, 2011, the Company had 6,298,230 warrants outstanding to purchase 3,149,115 common shares for $1.05 per share, expiring between June 20, 2012 and June 30, 2012. For the year ended December 31, 2011, 735,817 common shares were issued upon the exercise of 1,471,634 warrants (year ended December 31, 2010, 11,127,527 common shares were issued upon the exercise of 15,109,116 warrants). Included in warrants exercised in 2010 were 7,145,938 warrants to purchase 7,145,938 common shares for $14.4 million, assumed in the acquisition of Solana in November 2008. The Company issued 4,125, 036 Replacement Warrants in connection with its acquisition of Petrolifera during March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011.

Stock Options

As at December 31, 2011, the Company had a 2007 Equity Incentive Plan, formed through the approval by shareholders of the amendment and restatement of the 2005 Equity Incentive Plan, under which the Company's board of directors is authorized to issue options or other rights to acquire shares of the Company's common stock. On June 16, 2010, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the number of shares of common stock available for issuance thereunder from 18,000,000 shares to 23,306,100 shares.

The Company grants options to purchase common shares to certain directors, officers, employees and consultants. Each option permits the holder to purchase one common share at the stated exercise price. The options vest over three years and have a term of ten years, or three months after the grantee's end of service to the Company, whichever occurs first. At the time of grant, the exercise price equals the market price. For the year ended December 31, 2011, 1,695,049 common shares were issued upon the exercise of 1,695,049 stock options (year ended December 31, 2010—2,895,553; year ended December 31, 2009—1,391,028). The following options are outstanding as of December 31, 2011:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option	Number of Nonvested Options	Weighted Average Grant-Date Fair Value $/Option
Balance, December 31, 2010	10,943,058	$ 3.49	5,516,691	$ 2.68
Granted in 2011	4,215,996	7.94	4,215,996	4.84
Exercised in 2011	(1,695,049)	(2.70)	–	–
Vested in 2011	–	–	(2,940,822)	(2.26)
Forfeited in 2011	(600,003)	(6.70)	(576,669)	(4.06)
Balance, December 31, 2011	**12,864,002**	**$ 4.90**	**6,215,196**	**$ 4.22**

The weighted average grant date fair value for options granted in 2011 was $4.84 (2010—$3.36; 2009—$2.43). The weighted average grant date fair value for non-vested options at December 31, 2011 was $4.22 (2010—$2.68). The weighted average grant date fair value for options vested in 2011 was $2.26 (2010—$1.61; 2009—$1.38). The total fair value of stock options vested during 2011 was $6.6 million (2010—$5.1 million; 2009—$4.7 million).

The aggregate intrinsic value of options outstanding at December 31, 2011 is $14.7 million (2010—$49.9 million; 2009—$39.0 million) based on the Company's closing stock price of $4.80 at December 31, 2011 (December 31, 2010—$8.05; December 31, 2009—$5.73). The intrinsic value of options exercised in 2011 was $6.2 million (2010—$12.8 million; 2009—$2.9 million).

In 2011, the stock-based compensation expense was $13.7 million (2010—$8.5 million; 2009—$5.6 million) of which $11.4 million (2010—$7.2 million; 2009—$4.5 million) was recorded in G&A expense and $1.3 million (2010—$0.8 million; 2009—$0.8 million) was recorded in operating expense and $1.0 million (2010—$0.5 million; 2009—$0.3 million) was capitalized as part of exploration and development costs. At December 31, 2011, there was $11.7 million (2010—$6.1 million; 2009—$5.4 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

The table below summarizes stock options outstanding at December 31, 2011:

Range of Exercise Prices ($/option)	Number of Outstanding Options		Weighted Average Exercise Price $/Option	Weighted Average Expiry Years
0.50 to 2.00	1,195,837	$	1.12	4.6
2.01 to 3.50	4,310,250		2.47	6.8
3.51 to 5.50	621,666		4.52	8.3
5.51 to 7.00	3,132,753		5.94	8.4
7.01 to 8.40	3,603,496		8.23	9.1
Total	12,864,002	$	4.90	7.7

The table below summarizes exercisable stock options at December 31, 2011:

Range of Exercise Prices ($/option)	Number of Outstanding Options		Weighted Average Exercise Price $/ Option	Weighted Average Expiry Years
0.50 to 2.00	1,195,837	$	1.12	4.6
2.01 to 3.50	4,128,583		2.47	6.8
3.51 to 5.50	283,332		4.47	7.8
5.51 to 7.00	897,721		5.90	8.2
7.01 to 8.40	143,333		7.67	7.2
Total	6,648,806	$	2.89	6.6

The aggregate intrinsic value of options exercisable at December 31, 2011 is $14.2 million (2010—$49.4 million; 2009—$19.8 million) based on the Company's closing stock price of $4.80 at December 31, 2011 (December 31, 2010—$8.05; December 31, 2009—$5.73)

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model based on assumptions noted in the following table.

	Year Ended December 31,		
	2011	2010	2009
Dividend yield (per share)	$nil	$nil	$nil
Volatility	75% to 81%	84% to 90%	94% to 98%
Weighted average volatility	80%	89%	96%
Risk-free interest rate	0.4% to 1.4%	0.2% to 0.5%	0.4% to 0.6%
Weighted average risk-free interest rate	1.2%	0.3%	0.5%
Expected term	4 to 6 years	3 years	3 years

Weighted average shares outstanding

	Year Ended December 31,		
	2011	2010	2009
Weighted average number of common and exchangeable shares outstanding	273,491,564	253,697,076	241,258,568
Shares issuable pursuant to warrants	2,708,183	3,750,781	9,503,818
Shares issuable pursuant to stock options	5,143,498	7,402,966	5,797,322
Shares to be purchased from proceeds of stock options	(56,243)	(545,992)	(2,969,605)
Weighted average number of diluted common and exchangeable shares outstanding	281,287,002	264,304,831	253,590,103

Net income per share

At December 31, 2011, 3,726,999 (December 31, 2010—290,000; December 31, 2009—1,080,000) options to purchase common shares were excluded from the diluted income per share calculation as the instruments were anti-dilutive.

8. Asset Retirement Obligation

As at December 31, 2011, the Company's asset retirement obligation was comprised of a Colombian obligation in the amount of $5.5 million (December 31, 2010—$3.7 million), an Argentine obligation in the amount of $6.7 million (December 31, 2010—$1.1 million) and a Brazilian obligation in the amount of $0.5 million (December 31, 2010—nil). As at December 31, 2011, the undiscounted asset retirement obligation was $29.9 million. Revisions to estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling asset retirement obligations. Changes in the carrying amounts of the asset retirement obligations associated with the Company's oil and natural gas properties were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2011**	2010
Balance, beginning of year	**$ 4,807**	$ 4,708
Settlements	**(345)**	(286)
Disposal	**(172)**	(720)
Liability incurred	**867**	719
Liability assumed in a business combination (Note 3)	**4,901**	–
Foreign exchange	**17**	58
Accretion	**673**	328
Revisions in estimated liability	**1,921**	–
Balance, end of year	**$ 12,669**	$ 4,807
Asset retirement obligation—current	**$ 326**	$ 338
Asset retirement obligation—long term	**12,343**	4,469
Balance, end of year	**$ 12,669**	$ 4,807

9. Income Taxes

The income tax expense reported differs from the amount computed by applying the US statutory rate to income before income taxes for the following reasons:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2011**	2010	2009
Income before income taxes	**$ 234,247**	$ 94,406	$ 38,295
	35%	35%	35%
Income tax expense expected	**81,986**	33,042	13,403
Foreign currency translation adjustments	**(417)**	6,409	1,099
Impact of foreign taxes	**3,890**	(3,094)	(1,565)
Enhanced tax depreciation incentive	**–**	(7,971)	(3,380)
Stock-based compensation	**4,013**	2,381	1,814
Increase in valuation allowance	**36,815**	19,991	16,199
Branch and other foreign income pick-up in the United States and Canada	**(14,363)**	(3,957)	(5,931)
Non-deductible third party royalty in Colombia	**8,525**	5,506	3,532
Non-taxable gain on acquisition	**(7,595)**	–	–
Other permanent differences	**(5,524)**	4,927	(817)
Total income tax expense	**$ 107,330**	$ 57,234	$ 24,354
Current income tax	**136,015**	76,913	38,795
Deferred tax recovery	**(28,685)**	(19,679)	(14,441)
Total income tax expense	**$ 107,330**	$ 57,234	$ 24,354

	As at December 31,	
(Thousands of U.S. Dollars)	2011	2010
Deferred Tax Assets		
Tax benefit of loss carryforwards	$ 63,910	$ 27,527
Tax basis in excess of book basis	17,065	7,975
Foreign tax credits and other accruals	27,164	16,895
Capital losses	2,433	1,413
Deferred tax assets before valuation allowance	110,572	53,810
Valuation allowance	(102,796)	(48,958)
	$ 7,776	$ 4,852
Deferred tax assets—current	$ 3,029	$ 4,852
Deferred tax assets—long-term	4,747	–
	7,776	4,852
Deferred Tax Liabilities		
Long-term - book value in excess of tax basis	(186,799)	(204,570)
	(186,799)	(204,570)
Net Deferred Tax Liabilities	$ (179,023)	$ (199,718)

As at December 31, 2011, the Company has operating loss carryforwards of $361.6 million (December 31, 2010—$95.6 million) and capital losses of $13.7 million (December 31, 2010—$4.0 million). Of these losses, $339.8 million (December 31, 2010—$75.4 million) are losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the net operating loss carryforwards expire between 2012 and 2031 and the capital losses expire between 2012 and 2016, while certain other jurisdictions allow net operating losses to be carried forward indefinitely. Of the total net operating loss carryforwards, $1.2 million will begin to expire by 2012.

Equity tax for the year ended December 31, 2011 of $8.3 million represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years. The tax is payable in eight semi-annual installments over four years, but is expensed in the first quarter of 2011 at the commencement of the four-year period. The remainder of the equity tax liability at December 31, 2011 relates to an equity tax liability assumed upon the acquisition of Petrolifera.

As at December 31, 2011, the total amount of Gran Tierra's unrecognized tax benefits was approximately $20.5 million (December 31, 2010—$4.2 million), a portion of which, if recognized, would affect the Company's effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations. As at December 31, 2011, the amount of interest and penalties on unrecognized tax benefits included in current income tax liabilities in the condensed consolidated balance sheet was approximately $1.6 million. The Company had no material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2011.

Changes in the Company's unrecognized tax benefit are as follows:

(Thousands of U.S. Dollars)	
Unrecognized tax benefit at January 1, 2011	$ 4,175
Changes for tax positions relating to prior year	585
Additions to tax position related to the current year	15,740
Unrecognized tax benefit at December 31, 2011	**$ 20,500**

The Company and its subsidiaries file income tax returns in the U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is subject to income tax examinations for the calendar tax years ended 2005 through 2011 in most jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefits disclosed above within the next twelve months.

10. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	2011	2010
Trade	$ 71,384	$ 63,969
Royalties	37,936	18,064
VAT and withholding tax	24,962	16,438
Other	14,739	9,672
Total	$ 149,021	$ 108,143

11. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2011.

		As at December 31, 2011			
		Payments Due in Period			
(Thousands of U.S. Dollars)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Oil transportation services	$ 38,059	$ 13,280	$ 8,029	$ 7,100	$ 9,650
Drilling and geological and geophysical	41,034	39,550	1,484	-	-
Completions	23,053	15,273	7,780	-	-
Facility construction	32,195	15,673	16,522	-	-
Operating leases	7,798	4,567	2,779	452	-
Software and telecommunication	3,196	2,587	609	-	-
Consulting	897	843	54	-	-
Total	$ 146,232	$ 91,773	$ 37,257	$ 7,552	$ 9,650

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for 2011 was $3.0 million (2010—$2.3 million; 2009—$2.1 million).

Indemnities

Corporate indemnities have been provided by the Company to directors and officers for various items including, but not limited to, all costs to settle suits or actions due to their association with the Company and its subsidiaries and/or affiliates, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The maximum amount of any potential future payment cannot be reasonably estimated.

The Company may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on the Company's consolidated financial position, results of operations or cash flows.

Letters of credit

At December 31, 2011, we had provided promissory notes totaling $20.7 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contingencies

Ecopetrol and Gran Tierra Energy Colombia Ltd. ("Gran Tierra Colombia"), the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long term test of the Guayuyaco—1 and Guayuyaco—2 wells. There is a material difference in the interpretation of the procedure established in Clause 3.5 of Attachment-B of the Guayuyaco Association Contract. Ecopetrol interprets the contract to provide that the extended test production up to a value equal to 30% of the direct exploration costs of the wells is for Ecopetrol's account only and serves as reimbursement of its 30% back-in to the Guayuyaco discovery. Gran Tierra Colombia's contention is that this amount is merely the recovery of 30% of the direct exploration costs of the wells and not exclusively for the benefit of Ecopetrol. There has been no agreement between the parties, and Ecopetrol has filed a lawsuit in the Contravention Administrative Court in the District of Cauca regarding this matter. Gran Tierra Colombia filed a response on April 29, 2008 in which it refuted all of Ecopetrol's claims and requested a change of venue to the courts in Bogota. At this time no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. Ecopetrol is claiming damages of approximately $5.4 million.

Gran Tierra is subject to a third party 10% net profits interest on 50% of the Company's production from the Costayaco field that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There is currently a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through an arbitration which was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. We expect to receive the arbitrator's decision in March 2012. At this time no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. The disputed amount at December 31, 2011 is $9.6 million.

Gran Tierra has several lawsuits and claims pending for which the Company currently cannot determine the ultimate result. Gran Tierra records costs as they are incurred or become probable and determinable. Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

12. Financial Instruments, Fair Value Measurements and Credit Risk

At December 31, 2011 the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable, accrued liabilities. The fair value of long term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short term maturity of these instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. The Company does not have any financial assets or liabilities measured at fair value on the balance sheet at December 31, 2011.

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash and accounts receivables. The carrying value of cash and accounts receivable reflects management's assessment of credit risk.

At December 31, 2011, cash and cash equivalents includes balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with governments and financial institutions with strong investment grade ratings, or the equivalent in our operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in our operating areas.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. In 2011, the Company had one significant customer for its Colombian oil, Ecopetrol, and in Argentina the Company had three significant customers, Refiner, Shell and YPF.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's deferred tax liability, a monetary liability, which is mainly denominated in the local currency of the Colombian foreign operations. As a result, foreign exchange gains and losses must be calculated on conversion to the US dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Company holds no derivative instruments at December 31, 2011 or 2010 and does not use derivative financial instruments for speculative purposes. The Replacement Warrants (Note 3) met the definition of a derivative. Because the exercise price of the Replacement Warrants was denominated in Canadian dollars, which is different from Gran Tierra's functional currency, the Replacement Warrants were not considered indexed to Gran Tierra's common shares and the Replacement Warrants could not be classified within equity. Therefore the Replacement Warrants were classified as a current liability on Gran Tierra's condensed consolidated balance sheet. Furthermore, these derivative instruments did not qualify as fair value hedges or cash flow hedges, and accordingly, changes in their fair value were recognized as income or expense in the consolidated statement of operations and retained earnings with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The fair value of the Replacement Warrants was determined using Level 3 inputs.

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2011**	2010	2009
Realized financial derivative gain	**$ (1,522)**	$ –	$ (87)
Unrealized financial derivative (gain) loss	**–**	(44)	277
Derivative financial instruments (gain) loss	**$ (1,522)**	$ (44)	$ 190

13. Credit Facilities

Effective July 30, 2010, a subsidiary of Gran Tierra, Solana, established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve based facility has a maximum borrowing base up to $100 million and is supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia—Gran Tierra Colombia and Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million. Amounts drawn down under the facility bear interest at the USD LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expense. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. As at December 31, 2011 and 2010, the Company had not drawn down any amounts under this facility.

As part of the acquisition of Petrolifera, Gran Tierra assumed a reserve-backed credit facility with an outstanding balance as at the Acquisition Date of $31.3 million. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries.

Effective February 28, 2007, the Company entered into a credit facility with Standard Bank. As a result of re-negotiations concluded in August 2009, the maximum amount of the credit facility was $200 million with a $7 million borrowing base that could be re-determined semi-annually based on reserve evaluation reports. Amounts drawn down under the facility bore interest at the Eurodollar rate plus 4%. A stand-by fee of 1% per annum was charged on the un-drawn amount of the borrowing base. The facility was secured primarily by the assets of Gran Tierra Colombia and Solana Petroleum Exploration (Colombia) Ltd. This facility expired February 22, 2010.

Interest Expense

Interest expense on the reserve-backed credit facility for the 140 day period from the Acquisition Date to August 5, 2011, the date the facility was repaid, was $1.6 million. This amount is recorded in the Consolidated Statements of Operations as part of G&A expense.

14. Related Party Transactions

On January 12, 2011, the Company entered into an agreement to sublease office space to a company of which Gran Tierra's President and Chief Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $4,500 of operating and other expense.

On August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. For the year ended December 31, 2011, $2.8 million was incurred and capitalized under this contract (2010—$0.8 million) and at December 31, 2011, $nil was included in accounts payable related to this contract (December 31, 2010—$0.8 million).

On February 1, 2009, the Company entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses.

15. Subsequent Events

On February 17, 2012, in accordance with the terms of a farmout agreement, the Company gave notice to the other party to the farmout agreement that the Company would not enter into and assume its share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farmout agreement has terminated and the Company will not receive any interest in the block. Pursuant to the farmout agreement, the company is obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to the well that was drilled during the term of the farmout agreement. The notice of withdrawal is a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and we had acquired a participating interest. The Company expects to make that payment in the approximate amount of $26 million in March 2012.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

A. Reserve Quantity Information

Gran Tierra's net proved reserves and changes in those reserves for operations are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves have been assessed by independent qualified reserves consultants, GLJ Petroleum Consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. See Critical Accounting Estimates for a description of Gran Tierra's reserves estimation process.

Proved Reserves Net of Royalties [1]

	Colombia		Argentina		Brazil		Total	
	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)
Proved Developed and Undeveloped Reserves, December 31, 2008	17,681	1,162	1,557	–	–	–	19,238	1,162
Extensions and Discoveries	2,025	–	–	–	–	–	2,025	–
Purchases of Reserves in Place	(113)	–	–	–	–	–	(113)	–
Production	(4,284)	(49)	(337)	–	–	–	(4,622)	(49)
Revisions of Previous Estimates	5,482	–	71	756	–	–	5,554	756
Proved Developed and Undeveloped Reserves, December 31, 2009	20,791	1,113	1,291	756	–	–	22,082	1,869
Extensions and Discoveries	3,107	–	43	–	–	–	3,150	–
Purchases of Reserves in Place	–	–	–	–	–	–	–	–
Production	(4,945)	(269)	(284)	–	–	–	(5,229)	(269)
Revisions of Previous Estimates	3,532	388	62	(756)	–	–	3,594	(368)
Proved Developed and Undeveloped Reserves, December 31, 2010	22,485	1,232	1,113	–	–	–	23,598	1,232
Extensions and Discoveries	4,009	–	47	–	–	–	4,056	–
Purchases of Reserves in Place	238	13,797	4,639	4,825	396	–	5,273	18,622
Production	(5,349)	(268)	(727)	(1,143)	(43)	–	(6,119)	(1,411)
Revisions of Previous Estimates	4,042	(121)	72	–	–	–	4,114	(121)
Proved Developed and Undeveloped Reserves, December 31, 2011	25,425	14,640	5,144	3,682	353	–	30,922	18,322
Proved Developed Reserves, December 31, 2009 [2]	20,194	1,113	1,080	756	–	–	21,274	1,869
Proved Developed Reserves, December 31, 2010 [2]	18,528	1,232	940	–	–	–	19,468	1,232
Proved Developed Reserves, December 31, 2011 [2]	20,899	13,927	1,918	3,351	54	–	22,871	17,278

(1) Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation testing.

(2) Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

B. Capitalized Costs

	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
Capitalized Costs, December 31, 2010	$ 777,262	$ 238,119	$ (334,858)	$ 680,523
Colombia	256,596	46,004	(140,093)	162,507
Argentina	95,631	47,630	(44,509)	98,752
Brazil	10,594	52,441	(1,642)	61,392
Capitalized Costs, December 31, 2011	**$ 1,140,083**	**$ 384,194**	**$ (521,102)**	**$ 1,003,175**

C. Costs Incurred

Total Costs Incurred before DD&A	Colombia	Argentina	Brazil	Oil and Gas Total
As at December 31, 2008	$ 765,032	$ 35,224	$ –	$ 800,256
Property Acquisition Costs				
Proved	$ –	$ –	$ –	$ –
Unproved	–	–	–	–
Exploration Costs	24,103	246	–	24,349
Development Costs	48,232	4,721	–	52,953
As at December 31, 2009	$ 837,367	$ 40,191	$ –	$ 877,558
Property Acquisition Costs				
Proved	$ –	$ –	$	$ –
Unproved	–	–		–
Exploration Costs	63,115	26,404		89,519
Development Costs	41,057	7,248		48,305
As at December 31, 2010	$ 941,539	$ 73,843	$	$ 1,015,382
Property Acquisition Costs				
Proved	$ –	$ 58,458	$ 4,601	$ 63,059
Unproved	114,993	49,784	35,285	200,062
Exploration Costs	54,486	11,270	17,225	82,981
Development Costs	133,121	23,749	5,923	162,793
As at December 31, 2011	**$ 1,244,139**	**$ 217,105**	**$ 63,034**	**$ 1,524,277**

D. Results of Operations for Producing Activities

	Colombia	Argentina	Brazil	Total
Year ended December 31, 2009				
Net Sales	$ 248,834	$ 13,795	$ –	$ 262,629
Production Costs	(33,091)	(7,537)	–	(40,628)
Exploration Expense	–	–	–	–
DD&A	(126,261)	(8,312)	–	(134,573)
Income Tax (Expense) Recovery	(25,824)	1,470	–	(24,355)
Results of Operations	$ 63,658	$ (585)	$ –	$ 63,073
Year ended December 31, 2010				
Net Sales	$ 359,302	$ 13,984	$ –	$ 373,286
Production Costs	(50,431)	(8,808)	–	(59,239)
Exploration Expense	–	–	–	–
DD&A	(132,050)	(29,426)	–	(161,476)
Income Tax Expense	(51,047)	(5,687)	–	(56,734)
Results of Operations	$ 125,774	$ (29,937)	$ –	$ 95,837
Year ended December 31, 2011				
Net Sales	**$ 543,999**	**$ 48,016**	**$ 4,176**	**$ 596,191**
Production Costs	**(58,081)**	**(27,076)**	**(1,018)**	**(86,175)**
Exploration Expense	**–**	**–**	**–**	**–**
DD&A	**(140,093)**	**(44,509)**	**(1,642)**	**(186,244)**
Income Tax Expense	**(114,255)**	**5,489**	**–**	**(108,766)**
Results of Operations	**$ 231,570**	**$ (18,080)**	**$ 1,516**	**$ 215,006**

E. Standardized Measure of Discounted Future Net Cash Flows and Changes

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves. The 2011 twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within that twelve month period was $95.20 (2010—$71.50; 2009—$61.04) for Colombia, $54.26 (2010—$50.18; 2009—$37.35) for Argentina and $97.07 (2010—$nil; 2009—$nil) for Brazil. The calculated weighted average production costs at December 31, 2011 were $10.10 (2010—$10.48; 2009—$14.92) for Colombia, $28.50 (2010—$18.87; 2009—$20.73) for Argentina and $15.65 (2010—$nil; 2009—$nil) for Brazil. Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators. Future income taxes are computed by applying year end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows. Discounted future net cash flows are calculated using 10% mid-year discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

The Company believes this information does not in any way reflect the current economic value of its oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period.

	Colombia	Argentina	Brazil	Total
December 31, 2009				
Future Cash Inflows	$ 1,117,879	$ 55,076	–	$ 1,172,955
Future Production Costs	(312,950)	(29,140)	–	(342,090)
Future Development Costs	(91,867)	(4,923)	–	(96,790)
Future Site Restoration Costs	(1,415)	(566)	–	(1,981)
Future Income Tax	(208,237)	(5,771)	–	(214,008)
Future Net Cash Flows	503,410	14,676	–	518,086
10% Discount Factor	(109,043)	(2,659)	–	(111,702)
Standardized Measure	$ 394,367	$ 12,017	$ –	$ 406,384
December 31, 2010				
Future Cash Inflows	$ 1,621,461	$ 55,833	–	$ 1,677,294
Future Production Costs	(373,467)	(27,314)	–	(400,781)
Future Development Costs	(136,688)	(4,965)	–	(141,653)
Future Site Restoration Costs	(8,070)	(385)	–	(8,455)
Future Income Tax	(295,146)	–	–	(295,146)
Future Net Cash Flows	808,090	23,169		831,259
10% Discount Factor	(225,990)	(4,270)	–	(230,260)
Standardized Measure	$ 582,100	$ 18,899		$ 600,999
December 31, 2011				
Future Cash Inflows	**$ 2,535,662**	**$ 331,554**	**$ 34,244**	**$ 2,901,460**
Future Production Costs	**(459,955)**	**(179,277)**	**(11,667)**	**(650,899)**
Future Development Costs	**(145,513)**	**(50,742)**	**(4,900)**	**(201,154)**
Future Site Restoration Costs	**(12,420)**	**(3,063)**	**(525)**	**(16,008)**
Future Income Tax	**(500,700)**	**(18,207)**	**(1,215)**	**(520,121)**
Future Net Cash Flows	**1,417,074**	**80,265**	**15,937**	**1,513,276**
10% Discount Factor	**(369,112)**	**(26,274)**	**(2,543)**	**(397,929)**
Standardized Measure	**$ 1,047,963**	**$ 53,991**	**$ 13,394**	**$ 1,115,347**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	2011	2010	2009
Beginning of Year	**$ 600,999**	$ 406,384	$ 275,122
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	**(491,046)**	(313,840)	(222,479)
Net Changes in Prices and Production Costs Related to Future Production	**446,111**	208,649	147,810
Extensions, Discoveries and Improved Recovery, Less Related Costs	**206,762**	32,194	54,388
Development Costs Incurred during the Period	**106,291**	107,856	59,024
Revisions of Previous Quantity Estimates	**242,761**	140,893	149,597
Accretion of Discount	**81,422**	58,043	38,934
Purchases of Reserves in Place	**93,071**	–	–
Sales of Reserves in Place	**–**	–	3,035
Net Change in Income Taxes	**(148,529)**	(39,180)	(99,047)
Changes in Forecast Development Costs	**(22,495)**	–	–
End of Year	**$ 1,115,347**	$ 600,999	$ 406,384

2) Summarized Quarterly Financial Information

	Revenue and Other Income	Expenses	Income Before Income Taxes	Income Taxes	Net Income (Loss)	Basic Net Income (Loss) Per Share —Basic	Diluted Net Income (Loss) Per Share —Diluted
2011							
First Quarter	$ 122,519	$ 82,110	$ 40,409	$ 26,696	$ 13,713	$ 0.05	$ 0.05
Second Quarter	162,120	102,560	59,560	27,993	31,567	0.11	0.11
Third Quarter	151,033	71,974	79,059	29,974	49,085	0.18	0.17
Fourth Quarter	161,735	106,516	55,219	22,667	32,552	0.12	0.12
	$ 597,407	$ 363,160	$ 234,247	$ 107,330	$ 126,917	$ 0.46	$ 0.45
2010							
First Quarter	$ 93,110	$ 71,968	$ 21,142	$ 11,182	$ 9,960	$ 0.04	$ 0.04
Second Quarter	84,114	53,890	30,224	12,853	17,371	0.07	0.07
Third Quarter	84,569	81,952	2,617	5,894	(3,277)	(0.01)	(0.01)
Fourth Quarter	112,667	72,244	40,423	27,305	13,118	0.05	0.04
	$ 374,460	$ 280,054	$ 94,406	$ 57,234	$ 37,172	$ 0.15	$ 0.14

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.
None.

Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock trades on the NYSE Amex, and on the Toronto Stock Exchange ("TSX") under the symbol "GTE". In addition, the exchangeable shares in one of our subsidiaries, Gran Tierra Exchangeco, are listed on the TSX and are trading under the symbol "GTX".

As of February 21, 2012 there were approximately: 40 holders of record of shares of our common stock and 263,961,554 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately 8 holders of record of 6,223,810 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 8 holders of record of 8,512,707 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our common stock.

For the quarters indicated from January 1, 2010 through the end of the fourth quarter of 2011, the following table shows the high and low closing sale prices per share of our common stock as reported on the NYSE Amex.

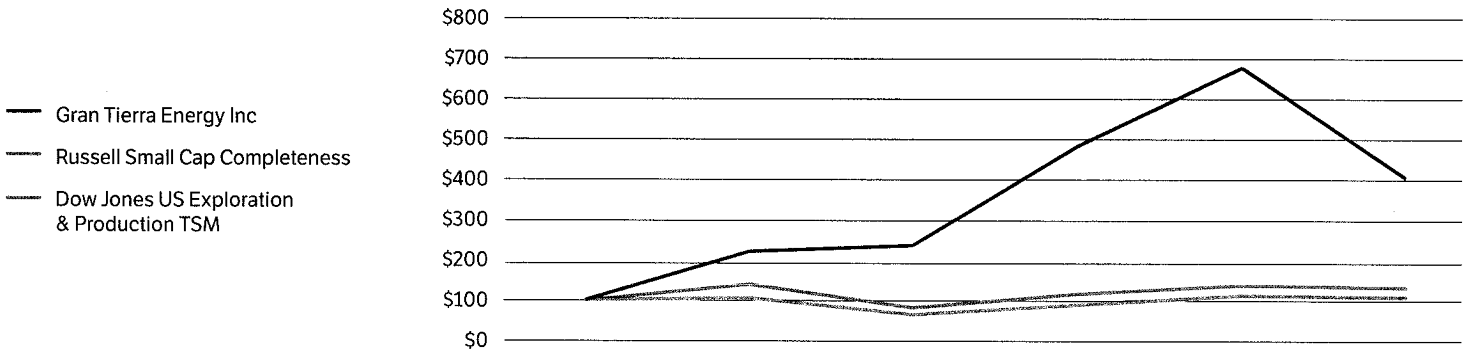
	High	Low
Fourth Quarter 2011	$ 6.47	$ 4.42
Third Quarter 2011	$ 7.20	$ 4.68
Second Quarter 2011	$ 8.17	$ 6.10
First Quarter 2011	$ 9.54	$ 7.75
Fourth Quarter 2010	$ 8.39	$ 7.23
Third Quarter 2010	$ 7.72	$ 5.06
Second Quarter 2010	$ 6.64	$ 4.70
First Quarter 2010	$ 6.08	$ 4.68

Dividend Policy

We have never declared or paid dividends on the shares of common stock and we intend to retain future earnings, if any, to support the development of the business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including current financial condition, operating results and current and anticipated cash needs. Under the terms of our credit facility we cannot pay any dividends if we are in default under the facility, and if we are not in default then are required to obtain bank approval for any dividend payments made by us exceeding $2 million in any fiscal year.

Performance Graph

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Gran Tierra Energy Inc, the Russell Small Cap Completeness Index, and the Dow Jones US Exploration & Production TSM Index



	12/06	12/07	12/08	12/09	12/10	12/11
Gran Tierra Energy Inc.	100.00	220.17	235.29	481.51	676.47	403.36
Russell Small Cap Completeness	100.00	104.85	63.98	88.10	111.56	107.19
Dow Jones US Exploration & Production TSM	100.00	140.30	82.74	117.09	138.63	132.95

The Dow Jones US Exploration and Production TSM was previously named the DJ Wilshire Exploration and Production.

*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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Chairman of the Board
President, Postell Energy Co. Ltd.

Ray Antony, CA
Corporate Director

Dana Coffield
President, Chief Executive Officer, Director

Gerald Macey
Corporate Director

Verne Johnson
President, KristErin Resources Inc.

Nicholas G. Kirton, FCA, ICD.D
Corporate Director

J. Scott Price
President, Prospect International Inc.

Executive Officers
Dana Coffield
President, Chief Executive Officer, Director

James Rozon
Acting Chief Financial Officer

Shane O'Leary
Chief Operating Officer

David Hardy
General Counsel and Corporate Secretary

Foreign Subsidiary Managers
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Annual General Meeting
The 2012 annual meeting of shareholders will be held on June 27, 2012, at 3:00 pm MDT at:
Calgary Petroleum Club, Devonian Room
319 Fifth Avenue SW, Calgary, Alberta
T2P 0L5, Canada

Material Requests
Gran Tierra Energy will supply a copy of the Form 10-K, including financial statements and schedules, without charge, upon receiving a written request for these materials. Please submit your requests to Jason Crumley by email at info@grantierra.com or by mail to:
300, 625 11 Avenue SW, Calgary, Alberta, Canada, T2R 0E1.

Gran Tierra Energy's filings are also available on a Website maintained by the Securities and Exchange Commission at: www.sec.gov and on SEDAR at www.sedar.com.

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