ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 4, 2009

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READER ADVISORY REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this AIF, including statements related to future capital expenditures, financing and capital activities, business strategy and goals, future commodity prices, reserves and resources estimates, drilling plans, development plans and schedules, future seismic activity, production levels and sources of growth thereof, results of exploration activities and dates that areas may come on-stream, royalties payable, contingent liabilities and government approvals, statements that contain words such as "may", "will", "would", "could", "should", "anticipate", "believe", "intend", "expect", "plan", "estimate", "budget", "outlook", "propose", "project", and statements relating to matters that are not historical fact constitute forward-looking information within the meaning of applicable Canadian securities legislation. Forward-looking information is subject to known and unknown risks and uncertainties attendant with oil and gas operations and is based on a number of assumptions which may prove to be incorrect.

In particular, in this AIF the Corporation has made assumptions with respect to the following:

- prices for oil and natural gas;
- oil and gas reserve and resource quantities, the discounted present value of future net cash flows from these reserves and the ultimate recoverability of reserves;
- timing and amount of future production, forecasts of capital expenditures and the sources of financing thereof;
- the amount, nature, timing and effects of capital expenditures;
- plans for drilling wells and the timing and location thereof;
- expectations regarding the negotiation and performance of contractual rights;
- operating and other costs;
- business strategies and plans of management;
- anticipated benefits and enhanced shareholder value resulting from prospect development and acquisitions; and
- treatment under the fiscal terms of Production Sharing Contracts and governmental regulatory regimes.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements if the assumptions underlying them prove incorrect, or if one or more of the uncertainties or risks described elsewhere in this AIF materializes. For further information, see "Risk Factors". Except as required pursuant to applicable securities laws, the Corporation does not intend, and does not assume any obligation, to update any forward-looking statements. The forward-looking statements contained in this AIF are expressly qualified by this advisory.

The information in this AIF is stated as at December 31, 2008, unless otherwise indicated.

PRESENTATION OF FINANCIAL INFORMATION

Addax Petroleum defines "Funds Flow From Operations" or "FFFO" as net cash from operating activities before changes in non-cash working capital. Management believes that in addition to net income, FFFO is a useful measure because it demonstrates Addax Petroleum's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Addax Petroleum also assesses its performance utilizing "Operating Netbacks" which it defines as the per barrel profit margin associated with the production and sale of crude oil and is calculated as the Funds Flow From Operations per barrel sold, prior to corporate charges. FFFO and Operating Netback are not recognized measures under Canadian GAAP. Readers are cautioned that these measures should not be construed as an alternative to net income or cash flow from operations determined in accordance with Canadian GAAP or as an indication of Addax Petroleum's performance. Addax Petroleum's method of calculating these measures may differ from other companies and accordingly, it may not be comparable to measures used by other companies.

GLOSSARY

In this AIF, unless the context otherwise requires, the following words and phrases have the meanings set forth below.

"**Aban**" means Aban Abraham Pte Ltd., a wholly owned subsidiary of Aban Offshore Limited;

"**Aban Abraham**" means the deep water drill ship owned by Aban that is under contract with the Corporation to drill up to ten wells;

"**Adanga Platform**" means the production platform located in the Adanga field on OML123, installed in 1986;

"Addax Energy" means Addax Energy S.A., a wholly-owned subsidiary of AOG which specializes in crude oil and product trading;

“**Addax Petroleum**” means Addax Petroleum Corporation, a corporation incorporated under the CBCA, together with all of its subsidiaries;

“**Addax Petroleum Holdings Limited**” or “**APHL**” means Addax Petroleum Holdings Limited, a corporation incorporated under the laws of the British Virgin Islands and a wholly owned subsidiary of Addax Petroleum, formerly known as Addax Petroleum N.V.;

“**Addax Petroleum N.V.**” or “**APNV**” means Addax Petroleum N.V., a corporation that was incorporated under the laws of the Netherlands Antilles and was a wholly owned subsidiary of Addax Petroleum that has been re-domiciled and continued under the laws of the British Virgin Islands as Addax Petroleum Holdings Limited;

“**Agip**” means ENI S.p.A together with all of the subsidiaries in its Agip division;

“**AIF**” or “**Annual Information Form**” means the Annual Information Form of the Corporation for the year ended December 31, 2008 and dated March 4, 2009;

“Amended Revised Taq Taq PSA” means the Amended Revised Production Sharing Agreement in respect of the Taq Taq licence area entered into between the KRG and Genel Energy International Limited and Addax International and dated February 26, 2008;

“**Anadarko**” means Anadarko Petroleum Corporation, together with all of its subsidiaries;

“**Antan Blend**” means the crude oil produced from OML123 offshore Nigeria, together with the crude oil produced by the OML114 Parties, which is lifted from the Antan Terminal;

“**Antan Crude Oil Supply Agreement**” means the Antan Crude Oil Supply Agreement dated with effect from January 1, 2008 between APHL and Addax Energy;

“**Antan Terminal**” means the floating production storage and offloading vessel and the tanker mooring and manifold platform located in OML123 where oil from OML123 is loaded onto ocean going tankers;

“**AOG**” means The Addax and Oryx Group Ltd., together with all of its subsidiaries other than Addax Petroleum;

“**AOG Holdings**” means AOG Holdings BV, a wholly owned subsidiary of AOG;

“**API**” means the American Petroleum Institute;

“Awoun” means the Awoun licence area, operated by Shell and located onshore in Gabon;

“Block 1” means the property designated as Block 1, located in the north end of the Joint Development Zone;

“**Block 2**” means the property designated as Block 2, located in the north end of the Joint Development Zone;

“**Block 3**” means the property designated as Block 3, located in the north end of the Joint Development Zone;

“**Block 4**” means the property designated as Block 4, located in the north end of the Joint Development Zone;

“**Board of Directors**” means the board of directors of Addax Petroleum;

“**Bogi Platform**” means the Bogi production platform located in the Disputed Area;

“**Brass River Blend**” means the crude oil produced from OML124 onshore Nigeria, and commingled with crude oil produced by other parties, which is transported to the Brass River Terminal;

“**Brass River Blend Crude Oil Supply Agreement**” means the Brass River Blend Crude Oil Supply Agreement dated with effect from January 1, 2008 between APHL and Addax Energy;

“**Brass River Terminal**” means the oil production export terminal located on the Nigerian coast where oil from OML124 is loaded onto ocean-going tankers;

“**Brent Crude**” means crude oil produced from the Brent system in the North Sea, a price setting benchmark in the world energy market;

“**Canadian GAAP**” means the generally accepted accounting principles and practices in Canada, including the principles set forth in the Canadian Institute of Chartered Accountants (“**CICA**”) Handbook published by CICA or any successor institute and which are applicable on the effective date as at which a calculation is required to be made in accordance therewith;

“**CBCA**” means the *Canada Business Corporations Act*, as amended;

“**Chevron**” means Chevron Corp., together with all of its subsidiaries;

“**CIM**” means the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society);

“**COGE Handbook**” means the Canadian Oil and Gas Evaluators Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society), as amended from time to time;

“**Common Share**” means a common share in the share capital of Addax Petroleum;

“**ConocoPhillips**” means ConocoPhillips Company, together with all of its subsidiaries;

“**Convertible Notes**” means $300 million 3.75 convertible notes due in 2012, distributed by a private placement that closed on May 30, 2007;

“**Corporation**” means Addax Petroleum;

“**Cost Oil**” means a percentage of available crude oil allocated to Addax Petroleum for recovery of costs, including exploration, development and production costs and expenses after the allocation of Royalty Oil;

“**Crude Oil Supply Agreements**” means the Antan Crude Oil Supply Agreement, the Brass River Blend Crude Oil Supply Agreement and the Okwori Crude Oil Supply Agreement;

“**Dated Brent Crude**” means the average of daily spot values of Brent Crude, as published by Platts Crude Oil Marketwire, averaged on a monthly basis for a given period;

“**developed non-producing reserves**” means those reserves that either have not been on production or have previously been on production but are shut in and the date of resumption of production is unknown;

“**developed producing reserves**” means those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty;

“**developed reserves**” means those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves in production. The developed category may be subdivided into producing and non-producing;

“DGH” means the Direction Générale des Hydrocarbures (Directorate General for Hydrocarbons) of Gabon;

“**Disputed Area**” means the area of OML123 offshore Nigeria awarded to Cameroon pursuant to the October 10, 2002 ruling of the International Court of Justice;

“**Ebughu Platform**” means the production platform located in the Ebughu field in OML123;

“Elf” means Elf Aquitaine, a predecessor company to TOTAL;

“Epaemeno licence” or **“Epaemeno”** means the Epaemeno licence area, which is located onshore in Gabon where the Corporation is engaged in exploration activities to discover and extract crude oil and natural gas liquids pursuant to a Production Sharing Contract;

“**ERHC Energy**” means ERHC Energy Inc., together with all of its subsidiaries;

“**Etame Crude**” means the crude oil produced from Etame Marin;

“Etame Marin” or **“Etame”** means the Etame Marin licence area, which is located offshore Gabon where the Corporation is engaged in the production of crude oil pursuant to a Production Sharing Contract;

“Express” means Express Petroleum & Gas Company Ltd., an indigenous Nigerian oil company;

“**ExxonMobil**” means ExxonMobil Corporation, together with all of its subsidiaries;

“**FFFO**” or “**Funds Flow From Operations**” means cash from operating activities before changes in non cash working capital. FFFO is not a standard measure under Canadian GAAP. Funds Flow From Operations measures presented in this AIF may not be comparable to other similarly titled measures of other companies. See “Presentation of Financial Information”;

“**FPSO**” means floating production storage and offloading vessel;

“**Genel Enerji**” means Genel Enerji AS., a Turkish registered company, together with all of its subsidiaries;

“**gross**” means in respect of reserves and production, the total reserves and production attributable to Addax Petroleum’s interest prior to the deduction of royalties and the relevant government’s or government corporation’s share of Profit Oil (which reserves are reported as “interest” in the Reserve Report);

“Gryphon Marin” means the Gryphon Marin licence area, which is located offshore Gabon where the Corporation is engaged in exploration activities to discover and extract crude oil and natural gas liquids pursuant to a Production Sharing Contract;

“**HSSE**” means Health, Safety, Security & Environment;

“Ibekelia” means the Ibekelia exploration property, located offshore Gabon, which is covered by a technical evaluation agreement;

“**IPO**” means the initial public offering of the Corporation by prospectus of 23,100,000 Common Shares at a price of CAD 19.50 per share;

“Iris Marin” means the Iris Marin licence area, which is located offshore Gabon where the Corporation is engaged in exploration activities to discover and extract crude oil and natural gas liquids pursuant to a Production Sharing Contract;

“Iroko” means the Iroko licence area offshore Cameroon where the Corporation is engaged in development and exploration activities to extract crude oil, natural gas liquids and natural gas pursuant to a Production Sharing Contract;

“**Izombe Flow Station**” means the Izombe production and flow station located in OML124;

“**JDA**” means the Nigeria/Sao Tome Joint Development Authority;

"**Joint Border Commission**" means the Nigeria Cameroon Mixed Commission established following the October 10, 2002 decision of the International Court of Justice to peacefully apply the decision;

"**Joint Development Zone**" or "**JDZ**" means the zone for joint development of petroleum and other resources established by treaty between Nigeria and the Democratic Republic of Sao Tome and Principe in the overlapping area of their respective maritime boundary claims;

"**Kiarsseny PSC**" means the Production Sharing Contract between the Government of Gabon and Tullow Oil for development and exploration activities to extract crude oil, natural gas liquids and natural gas from Kiarsseny;

"**Kiarsseny licence**" or **"Kiarsseny"** means the Kiarsseny licence area, which is located offshore Gabon, where the Corporation is engaged in exploration activities to discover and extract crude oil and natural gas liquids;

"**Knock Adoon**" means the floating production storage and offloading vessel described under the heading "Business of the Corporation — Properties Descriptions — Nigeria — OML123 — Production Facilities";

"**KRG**" means the Kurdistan Regional Government;

"**LPG**" means liquefied petroleum gas;

"LNG" means liquefied natural gas;

"Maghena" means the Maghena licence area, located onshore Gabon;

"MOL" means MOL Hungarian Oil and Gas plc, together with its subsidiaries;

"**NDDC**" means the Niger Delta Development Commission;

"**net**" means in respect of reserves and production, the total reserves and production attributable to Addax Petroleum's interest after deduction of Royalty Oil and the relevant government's or government corporation's share of Profit Oil;

"**net profit interest**" means an interest in an oil and gas property consisting of a share of profits after the recovery of the costs of development and production;

"**Ngosso**" means the Ngosso licence area offshore Cameroon where the Corporation is engaged in development and exploration activities to extract crude oil, natural gas liquids and natural gas pursuant to the Ngosso Concession;

"**Ngosso Concession**" or **"Concession Agreement"** means the concession contract between the Government of Cameroon, the Corporation and MOL for development and exploration activities to extract crude oil, natural gas liquids and natural gas from the Ngosso Property;

"**NI 51-101**" means the Canadian Securities Administrators' National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Nigerian Marginal Fields**" has the meaning given to it under the heading "Business of the Corporation — Fiscal Terms — Nigeria — Nigerian Marginal Fields";

"**NNPC**" means Nigerian National Petroleum Corporation together with all of its subsidiaries;

"**Noble Energy**" means Noble Energy Inc., together with all of its subsidiaries;

"**NSAI**" means Netherland, Sewell & Associates, Inc., independent oil and natural gas reservoir engineers;

"**Occidental**" means Occidental Petroleum Corporation, together with all of its subsidiaries;

"**Official Selling Price**" means the sales price published by NNPC for the sale of Nigerian government and NNPC crude oil entitlement to trade buyers for export. The Official Selling Price is issued by NNPC for each type of crude oil to be lifted by traders and published by the middle of each month prior to the month of lifting;

"**Oil Mining Lease**" or "**OML**" means a lease issued by the Nigerian government upon conversion of an Oil Prospecting Licence giving the lessee the exclusive right to produce petroleum from the geographical area covered by the Oil Mining Lease;

"**Oil Prospecting Licence**" or "**OPL**" means a licence issued by the Nigerian government to one or more oil companies (including NNPC) giving the licencee the exclusive right to explore for petroleum in the geographical area covered by the Oil Prospecting Licence;

"**Okwok**" means the Okwok licence area located in OML67 offshore Nigeria;

"**Okwori Blend**" means the crude oil produced from OML126 offshore Nigeria;

"**Okwori Crude Oil Supply Agreement**" means the Okwori Crude Oil Supply Agreement dated with effect from January 1, 2008 between APHL and Addax Energy;

"**Okwori Terminal**" means the floating production storage and offloading vessel and the tanker mooring and manifold platform located in OML126 where oil from OML126 is loaded into ocean going tankers;

"**OML114 Parties**" means Moni Pulo Limited and Brass Exploration Unlimited;

"**OML123**" means the property subject to Oil Mining Lease 123 issued by the Nigerian government to NNPC, for which Addax Petroleum has the exclusive right to produce crude oil pursuant to a Production Sharing Contract;

"**OML124**" means the property subject to Oil Mining Lease 124 issued by the Nigerian government to NNPC, for which Addax Petroleum has the exclusive right to produce crude oil pursuant to a Production Sharing Contract;

"**OML126**" means the property subject to Oil Mining Lease 126 issued by the Nigerian Government to NNPC, for which Addax Petroleum has the exclusive right to explore for, develop and produce crude oil pursuant to a Production Sharing Contract;

"OML137" means the property subject to Oil Mining Lease 137 issued by the Nigerian government to NNPC, for which Addax Petroleum has the exclusive right to produce crude oil pursuant to a Production Sharing Contract;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Operating Netback**" means the per barrel profit margin associated with the production and sale of crude oil and is calculated as the Funds Flow From Operations per barrel sold, prior to corporate charges;

"**OPL227**" means the property subject to Oil Prospecting Licence 227 to be issued by the Nigerian government to NNPC, for which Addax Petroleum, Express and PPI pursuant to which they are seeking the exclusive right to explore for, develop and produce crude oil pursuant to a Production Sharing Contract;

"**OPL291**" means the property subject to Oil Prospecting Licence 291 issued by the Nigerian government to NNPC, for which Addax Petroleum and Starcrest have the exclusive right to explore for, develop and produce crude oil pursuant to a Production Sharing Contract;

"**Oriental Energy**" means Oriental Energy Resources Limited, together with all of its subsidiaries;

"**Oriental Joint Venture Agreement**" means the joint venture agreement effective September 14, 2005 between Addax Petroleum and Oriental Energy;

"**PanAfrican**" means PanAfrican Energy Corporation (Mauritius) Limited, a subsidiary of Pan-Ocean Energy, which owned and operated Pan-Ocean Energy's oil exploration, production and marketing business in Gabon;

"Pan-Ocean Acquisition" means the arrangement under the provisions of Article 125 of the Companies (Jersey) Law 1991 whereby the Corporation purchased all of the issued and outstanding shares of PanAfrican and Pan-Ocean UK and certain other assets of Pan-Ocean Energy for aggregate cash consideration of CAD 1.605 billion and the assumption of CAD 6.8 million of net debt;

"**Pan-Ocean Energy**" means Pan-Ocean Energy Corporation Limited, together with all of its subsidiaries;

"**Pan-Ocean UK**" means Pan-Ocean Energy U.K. Ltd., a subsidiary of Pan-Ocean Energy that provided management and operational services to Pan-Ocean Energy;

"Panthere NZE" means the Panthere NZE licence area, located onshore Gabon;

"***Petroleum Act***" means the *Petroleum Act* (Nigeria) of 1969, as amended;

"**possible reserves**" means those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

"PPI" means Petroleum Prospects International Ltd., an indigenous Nigerian oil company;

"***PPT Act***" means the *Petroleum Profits Tax Act* (Nigeria) as amended;

"**Preferred Shares**" means preferred shares in the share capital of the Corporation, issuable in series;

"**probable reserves**" means those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves;

"**Production Sharing Contract**" or "**PSC**" means a contract whereby a government or government corporation contracts with a petroleum company to explore for, develop and extract petroleum substances in an area that is subject to a licence held by the government corporation, at the risk and expense of the petroleum company, in exchange for a share of production;

"**Profit Oil**" means the balance of available crude oil after the allocation of Royalty Oil, Tax Oil and Cost Oil;

"**proved reserves**" means those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**Rabi Blend**" means the crude oil produced from the Maghena Permit;

"**Realizable Price**" means "Realizable Price" as defined under the heading "Business of the Corporation - Fiscal Terms — Nigeria";

"**Remboué Crude**" means the crude oil produced from the Remboué Permit;

"Remboué Permit" or **"Remboué"** means the Remboué Permit, located onshore Gabon;

"**Reserves Report**" means the engineering report dated January 29, 2009 prepared by NSAI evaluating the crude oil reserves and certain prospective oil resources and contingent resources for gas and associated liquids attributable to Addax Petroleum's properties as of December 31, 2008, in accordance with the standards contained in the COGE

Handbook and the reserves and resources definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**reserves**" means those quantities of oil and gas anticipated to be economically recoverable from known accumulations;

"**Revised Taq Taq Production Sharing Agreement**" or "**Revised Taq Taq PSA**" means the Revised Production Sharing Agreement in respect of the Taq Taq licence area entered into between the KRG and Genel Enerji A.S., Genel Energy International Limited and Addax International and dated November 21, 2006;

"**Royalty Oil**" means either the amount of available crude oil allocated to the relevant government or government corporation, which will generate an amount of proceeds equal to the actual payment of Royalty and Concession Rentals, or the actual cash equivalent;

"Sangaw North" means the Sangaw North licence area, located in the Kurdistan region of Iraq, where the Corporation is engaged in development and exploration activities to extract crude oil pursuant to a PSC;

"Secured Revolving Debt Facility" means the five-year senior secured reducing revolving debt facility for the maximum principal amount of $1.5 billion dated January 22, 2007 among the Corporation, BNP Paribas, Natixis and Standard Chartered Bank as mandated lead arrangers, which was subsequently increased to $1.6 billion on April 30, 2007, as amended from time to time;

"**Shell**" means Royal Dutch Shell plc, together with all of its subsidiaries;

"**Sinopec**" means China Petroleum & Chemical Corporation, together with all of its subsidiaries;

"**Starcrest**" means Starcrest Nigeria Energy Limited, an indigenous Nigerian oil company;

"**Sterling Energy**" means Sterling Energy plc, a U.K.-based independent oil and gas company, together with all of its subsidiaries;

"**Subscription Receipts**" means the subscription receipts of the Corporation offered pursuant to the Supplemented Short Form PREP Prospectus of the Corporation dated August 10, 2006;

"**Taq Taq Crude**" means the crude oil produced from the Taq Taq licence area in the Kurdistan Region of Iraq;

"Taq Taq" or **"Taq Taq licence"** means the Taq Taq licence area, located in the Kurdistan region of Iraq, where the Corporation is engaged in development and exploration activities to extract crude oil pursuant to the Amended Revised Taq Taq PSA;

"**Taq Taq Operating Company**" or "**TTOPCO**" means Taq Taq Operating Company Limited;

"**Tax Oil**" means the amount of available crude oil allocated to the Nigerian government, which will generate an amount of proceeds equal to the actual payment of Nigerian petroleum profits tax;

"**TOTAL**" means TOTAL S.A., together with all of its subsidiaries;

"**TOTAL Gabon**" means TOTAL Gabon SA, together with its subsidiaries;

"**TPU**" means a temporary production unit which is used to produce petroleum on a temporary basis;

"**Trademark Agreement**" means the Trademark Agreement, made effective January 1, 2006, between Addax Petroleum N.V. and AOG;

"**Tullow Oil**" means Tullow Oil plc, together with all of its subsidiaries;

"UKLA" means the United Kingdom Listing Authority;

"**undeveloped reserves**" means those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned;

"Unsecured Revolving Debt Facility" means the two-year senior unsecured revolving debt facility for the maximum principal amount of $500 million dated April 25, 2008 and which is due April 25, 2010 among the Corporation, BNP Paribas, Calyon and Standard Chartered Bank as mandated lead arrangers; and

"**VAALCO**" means VAALCO Energy Inc., a US-based independent oil and gas company, together with all of its subsidiaries.

ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings.

Crude Oil and Natural Gas Liquids	
bbl	barrels
bbl/d	barrels per day
Mbbl	thousands of barrels
MMbbl	millions of barrels
Mbbl/d	thousands of barrels per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet

Other	
ftss	feet sub-sea
t/d	metric tonnes per day

Currency	
CAD	Canadian dollars
GBP	Pounds sterling

CONVERSIONS

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	thousand cubic metres	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres (“m^3”)	0.159
cubic metres (“m^3”)	bbl	6.290
feet (“ft”)	metres (“m”)	0.305
metres (“m”)	feet (“ft”)	3.281
miles (“mi”)	kilometres (“km”)	1.609
kilometres (“km”)	miles (“mi”)	0.621
hectares	acres	2.471
acres	hectares	0.405
acres	square kilometres (“km^2”)	0.00405
square kilometres (“km^2”)	acres	247.10
US gallons	litres	3.785
litres	US gallons	0.264

CURRENCY AND EXCHANGE RATE INFORMATION

Except as otherwise indicated, references to “$” or “dollar” in this AIF refer to the currency of the United States of America.

The following table sets forth the US/Canada exchange rates on the last trading day of the years indicated as well as the high, low and average rates for such years. The high, low and average exchange rates for each year were identified or calculated from spot rates in effect on each trading day during the relevant year. The exchange rates shown are expressed as the number of United States dollars required to purchase one Canadian dollar. These exchange rates are based on those published on the Bank of Canada’s website as being in effect at approximately noon on each trading day.

	Year ended December 31		
	2008	2007	2006
Year end	0.8166	1.0120	0.8581
High	1.0289	1.0905	0.9099
Low	0.7711	0.8437	0.8528
Average	0.9381	0.9304	0.8818

CORPORATE STRUCTURE

Incorporation and Address of Addax Petroleum Corporation

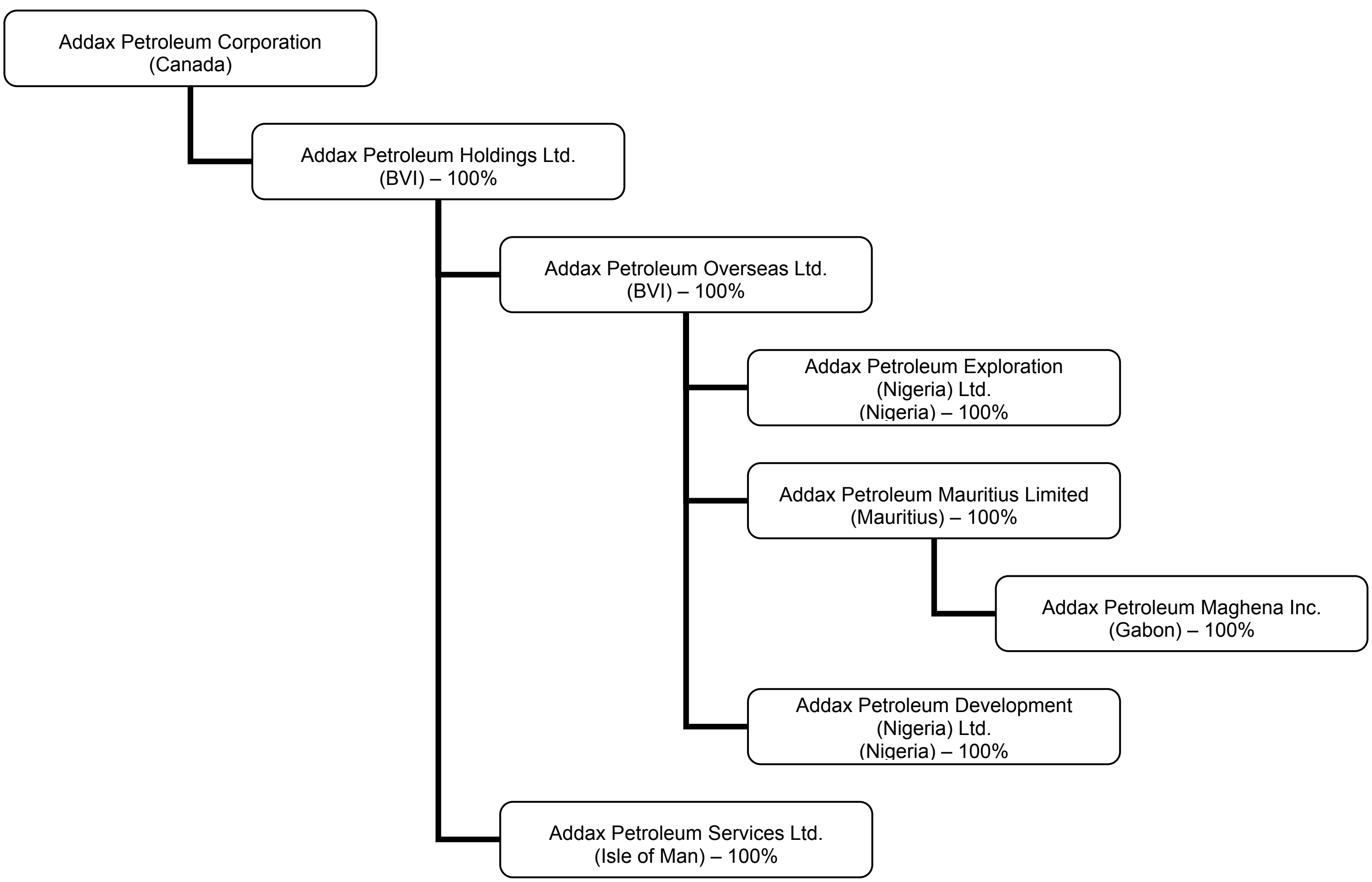
Addax Petroleum Corporation was incorporated under the *Canada Business Corporations Act* on September 6, 2005. On December 5, 2005, the articles of Addax Petroleum Corporation were amended to authorize the issue of an unlimited number of Preferred Shares, issuable in series, and to require that the Corporation have a minimum of three and a maximum of 15 directors.

The registered office of the Corporation is located at 3400 First Canadian Centre, 350 - 7th Avenue S.W., Calgary, Alberta, Canada. The Corporation's service office is located at 16, avenue Eugène-Pittard, 1206, Geneva, Switzerland.

Addax Petroleum is a reporting issuer (or the equivalent) in the jurisdictions of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, Newfoundland and Labrador, New Brunswick, Nova Scotia and Prince Edward Island and its Common Shares trade on the Toronto Stock Exchange ("TSX") under the symbol "AXC". On May 24, 2007, Addax Petroleum's common shares were admitted to the Official List of the UK Financial Services Authority and to trading on the main market for securities of the London Stock Exchange ("LSE") under the symbol "AXC". On May 31, 2007, Addax Petroleum's Convertible Notes were admitted to trading on the Professional Securities Market of the LSE.

Intercorporate Relationships

The Corporation beneficially and wholly owns, directly or indirectly, seven material subsidiaries. The chart below shows the inter-corporate relationships among the Corporation and its material subsidiaries as at March 4**,** 2009.



GENERAL DEVELOPMENT OF THE BUSINESS

Addax Petroleum was incorporated in September 2005. In February 2006, the Corporation completed its initial public offering of 23,100,000 Common Shares for aggregate gross proceeds of CAD 450,450,000 and its Common Shares were listed and posted for trading on the TSX under the symbol "AXC". Concurrent with the closing of the initial public offering, the Corporation acquired all of the issued and outstanding shares of Addax Petroleum N.V. ("APNV") in exchange for 117,000,000 Common Shares and CAD 55,575,000. In March 2007, APNV was re-domiciled and continued under the laws of the British Virgin Islands as Addax Petroleum Holdings Ltd.

As part of its acquisition of APNV, Addax Petroleum acquired an interest in four PSCs with the Nigerian government for OPL98, OPL118, OPL90 and OPL225 (now OML123, OML124, OML126 and OML137 respectively). All of these properties are operated by Addax Petroleum. Additionally, Addax Petroleum acquired a 60 per cent interest in the Ngosso licence area, offshore Cameroon. Ngosso is also operated by Addax Petroleum. In Gabon, Addax Petroleum acquired a 42.5 per cent interest in the Kiarsseny licence area, offshore Gabon. Kiarsseny is operated by Tullow Oil. In the Kurdistan Region of Iraq, Addax Petroleum acquired a 30 per cent interest in the Taq Taq licence area. Addax Petroleum and Genel Enerji have formed a joint venture company, Taq Taq Operating Company, to conduct petroleum operations at the Taq Taq licence area.

Three Year History

In March 2006, the Corporation signed a PSC with the JDA for a 33.3 per cent interest in Block 4 of the JDZ pursuant to a participation agreement with ERHC Energy. Addax Petroleum is the operator of Block 4. In addition, Addax Petroleum signed a PSC with the JDA for Block 3 of the JDZ for a 15 per cent interest under a joint operating agreement for the block where a subsidiary of Anadarko is the operator. In addition, the Corporation signed another PSC with the JDA for Block 2 of the JDZ for a 14.33 per cent interest in Block 2 pursuant to a participation agreement with ERHC Energy. Addax Petroleum also signed a joint operating agreement among the Block 2 co-venturers where Sinopec is the operator.

In April 2006, Addax Petroleum increased its interest in Block 4 of the JDZ from 33.3 per cent to 38.3 per cent by acquiring the 5.0 per cent participating interest held by Overt Ventures Ltd.

In June 2006, Addax Petroleum completed the acquisition of a 40 per cent interest in the Okwok field in licence area OML67. Under the Oriental Energy Joint Venture Agreement, Oriental retains a 60 per cent interest. Addax Petroleum conducts operations at Okwok in its capacity as technical advisor.

In August 2006, Addax Petroleum completed an offering of 14,750,000 Subscription Receipts of Addax Petroleum for aggregate gross proceeds of CAD 401,937,500. Each Subscription Receipt represented the right to receive one Common Share upon completion of the Pan-Ocean Acquisition.

In September 2006, Addax Petroleum completed the Pan-Ocean Acquisition for consideration of CAD 1.605 billion in cash and the assumption of CAD 6.8 million of net debt. Upon the closing of the Pan-Ocean Acquisition, the holders of Addax Petroleum's 14,750,000 Subscription Receipts received one Common Share per Subscription Receipt. A Business Acquisition Report in Form 51-102F4 in respect of the Pan-Ocean Acquisition is available at www.sedar.com.

In October 2006, Addax Petroleum entered into a farm-out agreement with Starcrest pursuant to which Addax Petroleum and Starcrest signed a PSC with NNPC in respect of OPL291, deepwater Nigeria. Addax Petroleum has an interest of 72.5 per cent and is the operator. OPL291 represents the mandatory relinquishment area of OPL216 relinquished by Chevron following its conversion to OML127 preceding the development of the Agbami field in OML127 by Chevron.

In November 2006, Addax Petroleum and Genel Enerji announced the execution of the Revised Taq Taq PSA in respect of the Taq Taq licence area in the Kurdistan Region of Iraq. At the same time Genel Enerji and Addax Petroleum also announced that Addax Petroleum had acquired an additional 15 per cent interest from Genel Enerji, thereby increasing the Corporation's total interest to 45 per cent. The original Taq Taq PSA was entered into between Genel Enerji and the KRG in January 2004. The Revised PSA extended the geographic scope of the original PSA to include further exploration acreage that includes the Kewa Chirmila prospect and gave the KRG the right to require that at a future date a government nominated entity is assigned an interest.

In January 2007, Addax Petroleum replaced its existing credit facility with a five-year senior secured revolving debt facility in the amount of $1.5 billion. See "Material Contracts".

In April 2007, Addax Petroleum announced that it had signed an agreement to acquire a fifty per cent interest in the Epaemeno licence area, covering approximately 331,100 acres onshore in Gabon, from BowLeven plc. Addax Petroleum also became the operator of the Epaemeno licence area.

Also in April 2007, Addax Petroleum syndicated its five-year senior secured revolving debt facility, which was also increased from $1.5 billion to $1.6 billion at that time. See "Material Contracts".

In May 2007, Addax Petroleum completed an offering by way of private placement of $300 million in principal amount of Convertible Notes, due in 2012. See "Material Contracts".

In September 2007, Addax Petroleum announced that it had entered into an agreement with Esso Exploration and Production Nigeria-Sao Tome (One) Limited ("Esso Nigeria-Sao Tome") to acquire Esso Nigeria-Sao Tome's 40 per cent working interest in Block 1 of the JDZ.

In February 2008, Addax Petroleum executed the Amended Revised Taq Taq PSA in respect of the Taq Taq licence area in the Kurdistan Region of Iraq. The purpose of the amendments was to bring the terms of the Revised Taq Taq PSA into conformity with the recently enacted oil and gas legislation in the Kurdistan Region of Iraq.

In March 2008, Addax Petroleum relinquished its interest in the Themis Marin licence area, offshore Gabon.

In April 2008, Addax Petroleum announced the execution of a PSC in respect of the Iroko licence area, covering approximately 3,890 acres offshore Cameroon. The Corporation acquired a 100% interest in, and operatorship of, the licence area.

In June 2008, Addax Petroleum acquired an additional 18 per cent working interest in the Iris Marin licence area, for a total working interest of 51.33 per cent, and operatorship.

Also in June 2008, Addax Petroleum announced the award of a 40 per cent working interest in OPL227, offshore Nigeria, a licence area covering approximately 210,300 acres. The Federal Government of Nigeria has not yet issued the formal deed of assignment in respect of this property.

In July 2008, an independent arbitral tribunal awarded Addax Petroleum an additional 7.2 per cent participating interest in JDZ Block 4, increasing the Corporation's total interest in the area to 45.5 per cent.

In August 2008, the Federal Government of Nigeria approved a proposal from Addax Petroleum, Chrome Oil Services Limited and Korea Gas Corporation for implementation of an integrated gas utilization project in Nigeria.

Also in August 2008, Addax Petroleum announced that it had entered into a two-year unsecured revolving credit facility for $450 million. The total amount of the facility was subsequently increased to $500 million in September 2008 following syndication. See "Material Contracts".

In September 2008, Addax Petroleum announced that it acquired a 50 per cent working interest in, and operatorship of, the Gryphon Marin licence area, covering approximately 2,409,200 acres offshore Gabon, subject to a 10 per cent back-in right held by the Government of Gabon for any development areas.

In October 2008, Addax Petroleum acquired a 33.33 per cent interest in the Sangaw North PSC, covering an area of approximately 121,600 acres in the Kurdistan Region of Iraq, subject to an assignment to the Korean National Oil Corporation (KNOC), and subject to the right of the KRG to require that at a future date a government nominated entity is assigned a 25 per cent interest, which would further reduce Addax Petroleum's interest to 20 per cent. KNOC subsequently exercised their option in the Sangaw North PSC, reducing the Corporation's working interest to 26.67 per cent.

In December 2008, Addax Petroleum announced the acquisition of an additional 18.75 per cent interest in the Gryphon Marin licence area, offshore Gabon, bringing the Corporation's total interest to 68.75 per cent.

BUSINESS OF THE CORPORATION

Addax Petroleum is an international oil and gas exploration and production company with a strategic focus on Africa and the Middle East, and is one of the largest independent oil producers in West Africa: The Corporation's annual average crude oil production has increased from 8.8 Mbbl/d in 1998 to 136.5 Mbbl/d in 2008. The Corporation's growth has been achieved by acquiring under-developed properties in established basins. Addax Petroleum believes that its demonstrated technical expertise, combined with its excellent operational reputation and strong community relationships throughout Africa and the Middle East, make it well positioned to continue to grow both reserves and production.

For the twelve months ended December 31, 2008, Addax Petroleum produced an average of 136,450 bbl/d, generated $1,850 million of FFFO and had total capital expenditures, including acquisitions, of $1,776 million. In 2009, Addax Petroleum has budgeted total capital expenditures of approximately $1.6 billion (excluding acquisitions), which are expected to result in total production averaging between 140,000 bbl/d and 145,000 bbl/d. This budget is consistent with Addax Petroleum's philosophy of funding capital expenditures from internally generated cash flow and has been determined using an average Brent Crude price of $60/bbl. Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, Addax Petroleum intends to reduce its capital expenditures such that total capital expenditures continue to be funded by internally generated cash flow. An average Brent Crude price of $40/bbl would result in a reduction of capital expenditures to approximately $1 billion and the associated reduced drilling and facilities expenditures would result in the Corporation's total production for 2009 averaging between 132,000 bbl/d and 137,000 bbl/d. As at December 31, 2008, Addax Petroleum had proved reserves of 214.2 MMbbl, proved plus probable reserves of 536.7 MMbbl and proved plus probable plus possible reserves of 738.4 MMbbl. In addition, the Corporation's best estimate unrisked prospective oil resources were 2,772.2 MMbbl (825.1 MMbbl risked) and best estimate contingent resources for gas and associated liquids were 2,820.4 Bcf and 83.5 MMbbl, respectively. See "Statement Of Reserves And Other Oil And Gas Data". All reserves and resources data are expressed on a gross working interest basis.

Strategy

Addax Petroleum's ongoing strategy is to build on the significant growth and profit enhancement opportunities within its existing licence areas while also pursuing new venture opportunities. The Corporation has achieved its growth by acquiring oil properties deemed by others to have limited remaining production potential and using its strong in-house technical and operational expertise to grow reserves and production in a cost effective manner. The Corporation has focussed on recruitment and retention of indigenous personnel, as well as active participation in and contribution to community development projects. Addax Petroleum believes it has an excellent reputation among government authorities as well as local and business communities, which has been critical in accessing new opportunities, obtaining necessary cooperation from stakeholders and successfully executing its projects. Addax Petroleum continues to look to extend this successful strategy to other regions in Africa and the Middle East where substantial growth opportunities exist.

Development Addax Petroleum intends to continue development in its existing properties by:

- investing in facilities and infrastructure to increase oil production, improving operating efficiencies and positioning itself to monetize natural gas resources; and
- initiating new development for recent discoveries and completing identified development projects.

Exploration Addax Petroleum's exploration strategy includes:

- identifying and evaluating exploration prospects on newly acquired properties and pursuing identified exploration prospects; and
- acquisition of seismic data for prospect identification and evaluation.

New Venture Opportunities Strategic acquisitions in West Africa and the Middle East form a significant element of Addax Petroleum's growth strategy, and are expected to continue to do so in the future. Addax Petroleum also continues to pursue opportunities within regions new to the Corporation in West Africa and the Middle East. The Corporation may also pursue opportunities in other regions outside its strategic focus area such as, but not limited to, North Africa and Central Asia.

The Corporation believes that it is well positioned to capitalize on numerous opportunities in its focus areas that arise as (i) national governments tender new acreage in future bid rounds; (ii) major international oil and gas companies reduce their involvement in onshore and shallow water offshore oil fields; and (iii) indigenous oil companies seek financially and technically strong partners to jointly develop their properties. The Corporation continues to implement its new venture strategy through the following initiatives:

- acquiring or farming-in to additional properties in its focus areas, such as OPL227, offshore Nigeria, the Iroko licence area, offshore Cameroon, as well as onshore and offshore Gabon licence areas; and acquiring an interest in the Sangaw North PSC and an additional interest in the Taq Taq licence area, both in the Kurdistan Region of Iraq; and
- building a significant exploration portfolio in the Deepwater Gulf of Guinea by acquiring interests in Blocks 1, 2, 3 and 4 located in the Joint Development Zone of Nigeria and the Democratic Republic of Sao Tome and Principe and in OPL291 offshore Nigeria.

Properties Summary

Addax Petroleum's properties in West Africa and the Middle East are as follows:

In Nigeria, Addax Petroleum has various interests in three PSCs, one Sole Risk Agreement and one joint venture agreement covering the following seven properties:

- 100 per cent interest in OML123, operated by Addax Petroleum. OML123 is located offshore in shallow water and produces medium to light quality crude oil (19° to 40° API), sold as Antan Blend;
- 100 per cent interest in OML124, operated by Addax Petroleum. OML124 is located onshore and produces medium to light quality crude oil (18° to 42° API), sold as Brass River Blend;
- 100 per cent interest in OML126, operated by Addax Petroleum. OML126 is located offshore in medium depth water and produces light quality crude oil (34° to 41° API) sold as Okwori Blend;
- 100 per cent interest in OML137, operated by Addax Petroleum. OML137 is an offshore exploration and appraisal property located in medium depth water, adjacent to OML126;
- 72.5 per cent interest in OPL291, operated by Addax Petroleum. OPL291 is an offshore exploration property located in deep water, adjacent to Chevron's Agbami field in OML127;
- 40 per cent interest in OPL227 (subject to receipt of formal deed of assignment), operated by Express. OPL227 is an offshore exploration property located in shallow water offshore of the western Niger Delta Basin; and
- 40 per cent interest in the Okwok field, operated by Oriental Energy. The Okwok field is an offshore

development property located in shallow water in ExxonMobil's OML67, adjacent to OML123. Addax Petroleum acts as technical advisor.

In Gabon, Addax Petroleum has various interests in nine PSCs and one technical evaluation agreement covering the following ten properties:

- 92.5 per cent interest in Maghena, operated by Addax Petroleum. Maghena is located onshore and produces medium to light quality crude oil (33° API);
- 92.5 per cent interest in Panthere NZE, operated by Addax Petroleum. Panthere NZE is located onshore and produces medium to light quality crude oil (31° API);
- 92 per cent interest in Remboué, operated by Addax Petroleum. Remboué is located onshore and produces medium to light quality crude oil (36° API);
- 68.75 per cent interest in Gryphon Marin, operated by Addax Petroleum. Gryphon Marin is an offshore exploration property north of Etame Marin;
- 51.33 per cent interest in Iris Marin, operated by Addax Petroleum. Iris Marin is an offshore exploration property;
- 50 per cent interest in Epaemeno, operated by Addax Petroleum. Epaemeno is an onshore exploration property, adjacent to Maghena and Awoun;
- 42.5 per cent interest in Kiarsseny, operated by Tullow Oil. Kiarsseny is an offshore exploration property;
- 40 per cent interest in Awoun, operated by Shell. Awoun is an onshore development property located adjacent to Maghena and Epaemeno;
- 40 per cent interest in Ibekelia, operated by Sterling Energy. Ibekelia is an offshore exploration property; and
- 31.36 per cent interest in Etame Marin, operated by VAALCO. Etame Marin is located offshore and produces medium to light quality crude oil (36° API).

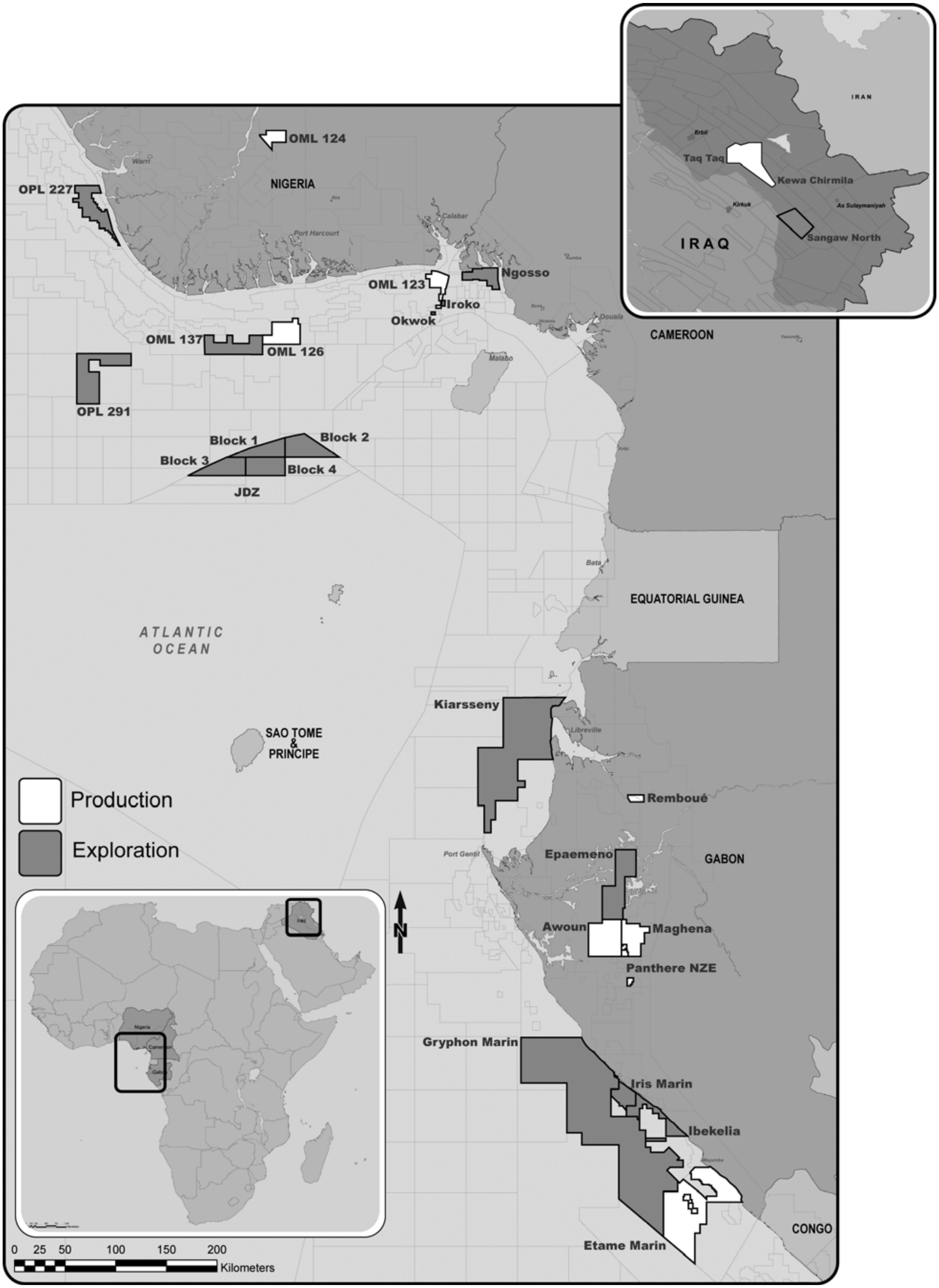
In Cameroon, Addax Petroleum has a 100 per cent interest in Iroko and a 60 per cent interest in Ngosso. Both Iroko and Ngosso are shallow water exploration properties and both are operated by Addax Petroleum.

In the Joint Development Zone, a deep water exploration region, Addax Petroleum has various interests in four PSCs as follows:

- 45.5 per cent interest in Block 4. Addax Petroleum is the operator;
- 40 per cent interest in Block 1. Chevron is the operator;
- 15 per cent interest in Block 3. Anadarko is the operator; and
- 14.33 per cent interest in Block 2. Sinopec is the operator.

In the Kurdistan Region of Iraq, Addax Petroleum has interests in two PSCs covering the following licence areas:

- 45 per cent interest in an Amended Revised Taq Taq PSA in respect of the Taq Taq licence area, subject to the right of the KRG to require that at a future date a government nominated entity is assigned a 20 per cent interest, which would reduce Addax Petroleum's interest to 36 per cent. The Taq Taq licence area is onshore and includes the Taq Taq field and the Kewa Chirmila prospect. Addax Petroleum and Genel Enerji have formed TTOPCO to carry out petroleum operations in the Taq Taq licence area; and
- 26.67 per cent interest in a PSC in respect of the Sangaw North licence area, following acquisition of 20 per cent interest by Korean National Oil Company in December 2008, and subject to the right of the KRG to require that at a future date a government nominated entity is assigned a 25 per cent interest, which would reduce Addax Petroleum's interest to 20 per cent.


OML 124
NIGERIA
Warri
OPL 227
Port Harcourt
Calabar
OML 123
Ngosso
Iroko
Okwok
Douala
OML 137
OML 126
CAMEROON
Malabo
OPL 291
Block 1
Block 2
Block 3
Block 4
JDZ
Bata
EQUATORIAL GUINEA
ATLANTIC
OCEAN
Kiarsseny
Libreville
SAO TOME
&
PRINCIPE
Production
Exploration
Remboué
Port Gentil
Epaemeno
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Awoun
Maghena
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Iris Marin
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0 25 50 100 150 200
Kilometers
IRAN
Erbil
Taq Taq
Kewa Chirmila
Kirkuk
As Sulaymaniyah
IRAQ
Sangaw North

Properties Summary Table

The following table summarizes the production, development and exploration properties of the Corporation.

				Average Oil Production		Gross Oil Reserves[(1)(2)(3)]		
Country/ Region	**Licence**	**Addax Petroleum Interest**	**Net Area[(1)(3)]**	**December 2008**	**12 Months Ended December 31, 2008**	**Proved**	**Proved plus Probable**	**Proved plus Probable plus Possible**
		(%)	*(acres)*	*(bbl/d)*	*(bbl/d)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Nigeria	OML123	100.00	90,700	62,160	58,420	81.0	190.2	249.6
	OML124	100.00	74,100	5,150	7,230	20.2	65.7	105.2
	OML126	100.00	178,300	46,280	42,330	32.6	42.9	73.1
	OML137	100.00	209,500	-	-	-	17.2	21.9
	OPL291	72.50	230,600	-	-	-	-	-
	OPL227	40.00	84,100	-	-	-	-	-
	Okwok	40.00	9,000	-	-	-	7.9	9.1
	subtotal		**876,300**	**113,590**	**107,980**	**133.8**	**324.0**	**458.9**
Gabon	Maghena	92.50	150,200	18,000	18,110	24.9	29.0	31.8
	Panthere NZE	92.50	27,500	1,350	1,610	17.9	33.9	41.3
	Remboué	92.00	29,600	360	590	1.5	6.1	7.2
	Gryphon Marin	68.75	1,656,300	-	-	-	-	-
	Iris Marin	51.33	51,100	-	-	-	-	-
	Epaemeno	50.00	165,500	-	-	-	-	-
	Kiarsseny	42.50	571,600	-	-	-	-	-
	Awoun	40.00	109,900	3,030	1,480	12.6	17.4	19.6
	Ibekelia	40.00	67,000	-	-	-	-	-
	Etame Marin	31.36	238,200	6,260	6,680	9.8	16.9	27.1
	subtotal		**3,066,900**	**29,000**	**28,470**	**66.7**	**103.3**	**127.0**
Kurdistan Region of Iraq	Taq Taq	45.00	105,800	-	-	13.7	109.5	152.6
	Sangaw North	26.67	32,400	-	-	-	-	-
Cameroon	Iroko	100.00	3,900	-	-	-	-	-
	Ngosso	60.00	70,300	-	-	-	-	-
JDZ	Block 1	40.00	69,600	-	-	-	-	-
	Block 2	14.33	24,500	-	-	-	-	-
	Block 3	15.00	24,700	-	-	-	-	-
	Block 4	45.50	96,300	-	-	-	-	-
Total[(4)]			**4,370,700**	**142,590**	**136,450**	**214.2**	**536.7**	**738.4**

Notes:

(1) Area presented excludes the area in the Disputed Area in OML123. Reserves presented exclude reserves in the Disputed Area of OML123 offshore Nigeria except for certain reserves attributable to existing producing wells in the Disputed Area which amount to proved reserves of 0.7 MMbbl. Reserves presented include reserves associated with partner carry on the Okwok field.

(2) As at December 31, 2008 as reported in the NSAI Reserve Report under “Forecast Prices and Costs Case”.

(3) For Taq Taq, the area presented assumes the Corporation’s current 45 percent working interest whereas the reserves presented assume a working interest of 36 per cent after giving effect to KRG back-in rights.

(4) Columns may not add due to rounding.

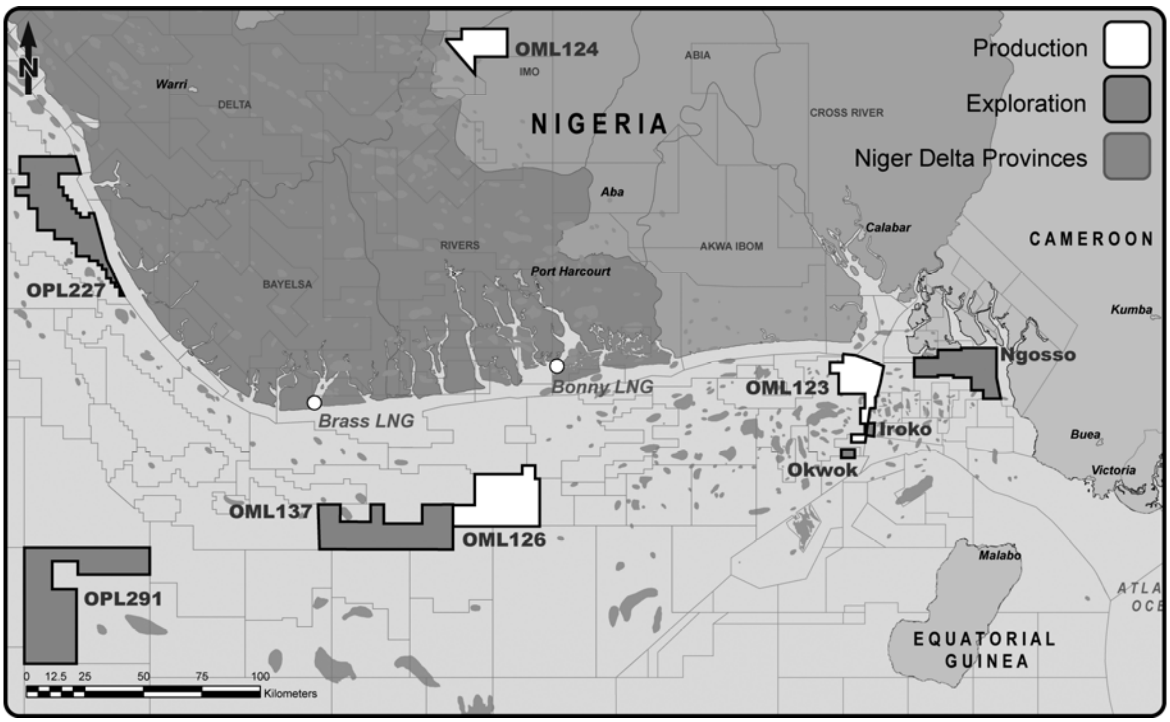
Properties Descriptions

Addax Petroleum’s principal oil and gas properties are in the West African countries of Nigeria, Gabon and Cameroon, as well as in the Joint Development Zone and the Kurdistan Region of Iraq.

The future development and exploration plans for each of Addax Petroleum’s properties are as described below. Due to the allocation of resources, well results and potentially unforeseen circumstances, the future development and exploration plans may change significantly throughout the planning period.

Nigeria

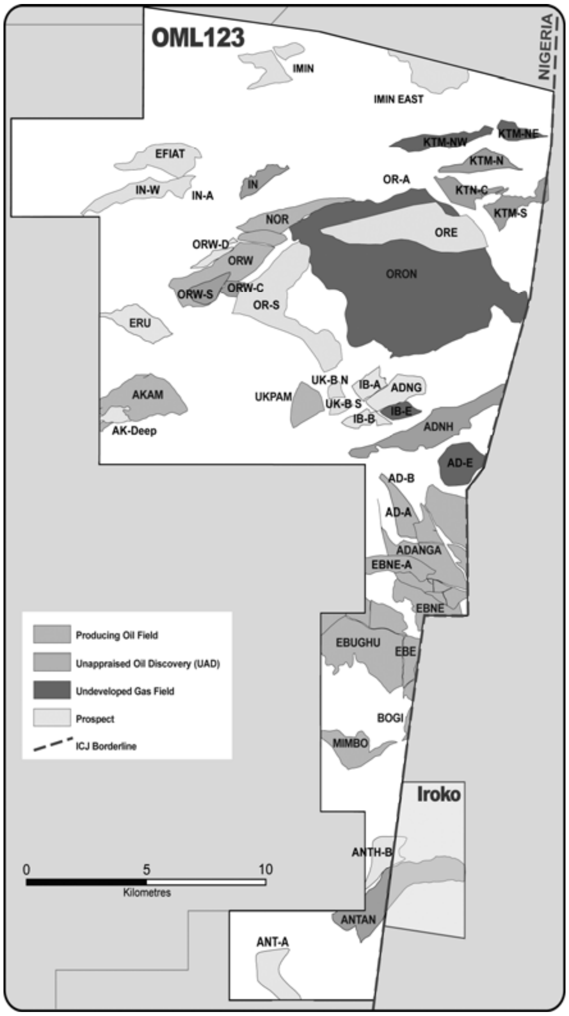
Within Nigeria, Addax Petroleum has various interests in three PSCs (OML123/124, OML126/137 and OPL291), one Sole Risk Agreement (OPL227) and one joint venture agreement (Okwok) covering six offshore properties and one onshore property. Addax Petroleum is the operator of five properties. On Okwok, the Corporation acts as technical advisor. On OPL227, Addax Petroleum will act as technical advisor.. OML123, OML124 and OML126 are producing; OML137 is under appraisal leading to development; and exploration activities are under way on OPL291. In 2008, the Corporation had capital expenditures totalling $1,200 million (including acquisitions) and produced an average of 107,980 bbl/d from its Nigerian properties. In 2009, the Corporation has budgeted capital expenditures of $1,007 million with associated total production from Nigeria averaging between 108,000 bbl/d and 112,000 bbl/d. Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, Addax Petroleum intends to reduce capital expenditures such that total capital expenditures continue to be funded by internally generated cash flow. The Corporation believes that an average Brent Crude price of $40/bbl would result in a reduction of capital expenditures to approximately $450 million and that the associated reduction on drilling and facilities spending would result in total production in Nigeria averaging between 100,000 bbl/d and 104,000 bbl/d for 2009. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for Nigeria to be 133.8 MMbbl, gross proved plus probable reserves to be 324.0 MMbbl and gross proved plus probable plus possible reserves to be 458.9 MMbbl.



In 2008 the development of the natural gas industry and cessation of natural gas flaring associated to oil production remained a high priority for the Nigerian government. The Corporation's existing PSCs in Nigeria relate solely to commercial oil development but include the right to negotiate commercial terms with NNPC for natural gas development in the properties. Addax Petroleum's natural gas strategy is intended to ensure that the Corporation ceases associated natural gas flaring and also to position the Corporation to assist with, and participate in, the monetization of existing and future associated and non-associated natural gas resources.

Together with its partners, Chrome Oil and KOGAS, Addax Petroleum received approval from the Federal Government of Nigeria for its proposed implementation of an integrated gas utilization project in Nigeria. The project is intended to include the exploration and development of gas fields in Nigeria, including OML137, to secure the gas reserves necessary to commercialise a new LNG production facility of up to 10 million tonnes per annum, to be situated on Brass Island in Bayelsa State. Also included as part of the overall project would be a power generation facility with capacity of up to 1,000 megawatts and provide feedstock for the development of petrochemical facilities. As part of the approval, the consortium has been instructed to cooperate with the relevant government authorities to establish fiscal and commercial terms for the upstream and downstream activities that meet the required investment levels for all participants in the project. This project is in the preliminary stages of development and there is no guarantee that facilities will be developed as planned. As at December 31, 2008, Addax Petroleum's gross working interest best estimate contingent resources for gas and associated liquids in Nigeria were estimated to be 2,820.4 Bcf and 83.5 MMbbl, respectively.

OML123



Overview

OML123 is the Corporation's largest property as measured by reserves and production. During 2008, OML123 produced an average of 58,420 bbl/d of oil from 56 wells. Oil gravity ranges between 19° and 40° API. As at December 31, 2008, the Corporation's gross proved reserves for OML123 were estimated to be 81.0 MMbbl and gross proved plus probable reserves to be 190.2 MMbbl. The Corporation expects its production from OML123 to average between 61,000 bbl/d and 64,000 bbl/d in 2009 under its existing capital expenditure budget. A reduction of capital expenditures to correspond with an average Brent Crude price of $40/bbl would result in total production from OML123 averaging between 56,000 bbl/d and 59,000 bbl/d in 2009.

OML123 is located offshore approximately 60 km south of the town of Calabar in the south-eastern part of Nigeria and covers an area of 90,700 acres (367 km^2) in water depths ranging from three to 40 m. OML123 contains nine producing oil fields (Adanga, Oron West, North Oron, Ebughu and extensions, Adanga North Horst, Inagha, Akam, Bogi and Mimbo) and two undeveloped oil fields (Kita Marine and Antan). There are also three unappraised oil discoveries (Adanga East, Adanga West and Ebughu NE-A), one large 8,600 acre (35 km^2) undeveloped gas discovery (Oron East) and several exploration prospects.

The Disputed Area includes 8,400 (33.9 km^2) of OML123. The Joint Border Commission, set up by the governments of Nigeria and Cameroon to study the implications of the International Court of Justice ruling, has not yet decided how the Corporation's operations will be treated. The Disputed Area has been excluded from the acreage and property descriptions in this AIF. Reserves presented in this AIF exclude reserves in the Disputed Area except for certain reserves attributable to existing producing wells, in the Disputed Area which amount to proved reserves of 0.7 MMbbl.

Production and Reserves

The following table summarizes the Corporation's production and reserves in OML123.

		Average Oil Production		Gross Oil Reserves(1)(2)		
Field	**Number of Oil Producing Wells(3)**	**December 2008** *(bbl/d)*	**12 Months Ended December 31, 2008** *(bbl/d)*	**Proved** *(MMbbl)*	**Proved plus Probable** *(MMbbl)*	**Proved plus Probable plus Possible** *(MMbbl)*
Adanga	17	21,610	20,810	28.1	44.2	52.1
Oron West and North Oron	16	24,620	21,830	23.5	38.3	44.5
Ebughu (and extensions)	18	11,140	12,600	12.7	17.1	22.7
Adanga North Horst	2	2,470	2,340	6.7	27.5	42.9
Inagha	1	2,035	330	2.1	3.0	3.0
Antan	-	-	-	-	15.1	25.8
Kita Marine (and extensions)	-	-	-	7.1	42.8	47.8
Other Producing Fields	2	280	520	0.8	2.2	10.8
Total	**56**	**62,160**	**58,420**	**81.0**	**190.2**	**249.6**

Columns may not add due to rounding

Notes:

(1) As at December 31, 2008, as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) Reserves presented exclude reserves in the Disputed Area of OML123 offshore Nigeria except for certain reserves attributable to existing producing wells in the Disputed Area which amount to proved reserves of 0.7 MMbbl.

(3) As at December 31, 2008.

Production Facilities

The producing fields in OML123 are operated as a common development area. The key production facility is the Knock Adoon, an FPSO which gathers produced crude oil from production or wellhead platforms on each field. At the OML123 FPSO, crude oil is processed to export specifications, stored and offloaded directly to ocean-going tankers.

The Knock Adoon has a nameplate processing capacity of 60 Mbbl/d of crude oil, a total liquids (oil and water) processing capacity of 140 Mbbl/d, a storage capacity of 1.7 MMbbl of crude oil and incorporates an off-loading buoy terminal to better facilitate offloading during periods of strong currents and to accommodate larger tankers. The Knock Adoon is under a time charter with a subsidiary of Fred Olsen Production A.S., the primary term of which is anticipated to expire in June 2014, with extension periods thereafter of up to a further eight years at the Corporation's option.

In order to maximize the use of the OML123 production facilities, Addax Petroleum has an ongoing agreement with the OML114 Parties who operate the adjacent OML114, to store and export all of the crude oil produced from their licence area. In return, the OML114 Parties pay the Corporation for their share of the expenses for the operation of the OML123 FPSO. As well, in 2008 the Corporation accelerated its OML123 infrastructure development to upgrade its oil handling capabilities as well as the provision of water injection and gas gathering facilities.

Associated natural gas produced on OML123 is currently used for gas lift and fuel. The Corporation has completed the first stage of a major infrastructure project to provide for increased oil processing, water injection for improved oil recovery and increased gas compression for gas lift at Adanga North in OML123 and plans to complete the next stage of the project to be operational by 2010. In addition, the Corporation is also studying gas monetization opportunities such as supplying the excess produced gas to shore for power generation or industrial development. As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate contingent resources for gas and associated liquids resources for OML123 to be 1,013.0 Bcf and 25.2 MMbbl, respectively. In 2009, the Corporation has budgeted to commence Adanga North Horst development and the associated water injection facilities.

Fields

Adanga

The Adanga field, discovered in 1980 and producing since 1986, is Addax Petroleum's principal producing field in OML123. During 2008, Adanga produced an average of 20,810 bbl/d of oil from 17 wells with an average watercut of 12 per cent. Oil gravity ranges from 24° to 40° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Adanga field to be 28.1 MMbbl and gross proved plus probable reserves to be 44.2 MMbbl.

The Adanga field is located in water depths ranging from 10 to 20 m and covers an area of approximately 2,800 acres (11.3 km^2) in the central part of OML123. First production started in 1986 from the Adanga main block through one vertical and eight deviated wells drilled from the Adanga Platform. Following a detailed 3D seismic interpretation, Addax Petroleum modelled the field in 1999-2000 and undertook an extensive appraisal and development drilling program in the southern blocks, beginning in 2001. In 2008, the Corporation drilled two water injection wells and initiated water injection using facilities installed on the OML123 FPSO. Most of the field's well completions are equipped with gas lift capability. In 2009, the Corporation has budgeted to drill two wells and complete the related facilities tie-in work at Adanga.

Adanga field wells produce through the Adanga Platform and three satellite wellhead platforms, installed in 2003. In 2004 a new riser platform tied-in to a leased TPU was commissioned at Adanga, at which time all production was handled by the TPU. The TPU now handles all initial processing in the Adanga area prior to pumping to the FPSO. In addition, the TPU allows production from the wells in the nearby Ebughu field extensions, which could not otherwise be accommodated on the Adanga Platform or on the Ebughu Platform. Adanga Platform redevelopment commenced in 2006, including the acquisition of the TPU, and continued in 2008. The Adanga Platform redevelopment will enable production to be routed to both the TPU and the Adanga Platform and to accommodate the gathering of the associated gas.

Oron West and North Oron

Oron West was discovered by Addax Petroleum in 2002 and North Oron was successfully appraised in the same year. The Corporation commenced oil production from Oron West and North Oron in 2004. During 2008, Oron West and North Oron produced an average of 21,830 bbl/d from 16 wells with a watercut range of between two percent and 20 percent. Oil gravity ranges between 31° and 40º API in Oron West and averaged 27º API in North Oron. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Oron West and North Oron fields to be 23.5 MMbbl and gross proved plus probable reserves to be 38.3 MMbbl.

These fields are located in water depth of approximately 8 m and cover an area of approximately 1,200 acres (4.9 km^2) in the northwest sector of OML123. In 2008, the Corporation drilled nine production wells and two water injection wells on Oron West as well as installing a production well jacket (Oron West South). The Corporation has budgeted to drill two production wells at Oron West, and one production well at North Oron as well as completing related facilities tie-in work in 2009.

Ebughu (and extensions)

The Ebughu field, discovered in 1980 and producing since 1988, along with the extensions is Addax Petroleum's third largest producing field in OML123. During 2008, Ebughu produced an average of 12,600 bbl/d of oil from 18 wells with an average watercut of 45 per cent. Oil gravity ranges between 20º to 33° API in the Ebughu field and 29º API in its northeast extension. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Ebughu field and extensions to be 12.7 MMbbl and gross proved plus probable reserves to be 17.1 MMbbl.

The Ebughu field is located in water depth of approximately 30 m and covers an area of approximately 2,600 acres (10.6 km^2) in the southern part of OML123. Following a successful three-well appraisal program in 1984, the prior operator installed the Ebughu Platform in 1988 and completed two wells which began producing in 1988. In 1996, a pilot horizontal production well was drilled between the existing two wells. Since 1999, Addax Petroleum has embarked on an extensive appraisal and development drilling program resulting in the discovery of five field extensions. In 2007, the Corporation drilled two horizontal wells at Ebughu East, two horizontal wells at Ebughu Main and one horizontal well at Ebughu North East. The Corporation did not drill any additional wells on Ebughu in 2008. In 2009, the Corporation has budgeted to drill two production wells and complete related facilities tie-in work.

Adanga North Horst

The Adanga North Horst field was discovered in 1986 and originally appraised in 1996. In 2006, the Corporation successfully re-appraised the field and full field development commenced at the end of 2007. During 2008, Adanga North Horst produced an average of 2,340 bbl/d from two wells with no water production. Oil gravity averaged between 19 º and 24º API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Adanga North Horst field to be 6.7 MMbbl and gross proved plus probable reserves to be 27.5 MMbbl.

The Adanga North Horst field is located in 10 m water depth and covers an area of approximately 1,100 acres (4.5 km^2) in the central part of OML123. Full field development began in 2008, including two platforms and the drilling of ten production wells and two water injectors. In 2009, the Corporation has budgeted to drill 11 production wells, install water injection facilities, and complete related facilities tie-in work.

Inagha

The Inagha field was discovered in 2002. The field is located two kilometres north of the Oron complex in 23 feet of water. Development of the Inagha field commenced in October 2008 with the drilling of the IN-2H well from the Oron W-S platform. The well was drilled in the I-4 reservoir to a measured depth of 11,520 feet with 1,500 feet of horizontal drain. Production from the Inagha field commenced in November 2008. During 2008, Inagha produced an average of 330 bbl/d of oil from one well with an average watercut of four per cent. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Inagha field to be 2.1 MMbbl and gross proved plus probable reserves to be 3.0 MMbbl. In 2009, the Corporation has budgeted to drill an exploration well in the nearby Inagha West prospect.

Antan

The Antan field was discovered and appraised in 2007 and the Corporation is now planning full field development. The Antan-1X exploration well discovered a new accumulation which encountered three oil-bearing reservoir intervals with approximately 104 feet of aggregated net pay. One of the three reservoir intervals was tested and flowed at a rate of approximately 470 bbl/d of between 16° and 18º API oil. The true flow potential of the interval was not reached because of sand control measures implemented during the test. The Antan discovery was successfully appraised by the Antan-2X well, a down-dip step-out well approximately 0.8 kilometres from the Antan-1X well, which encountered approximately 41 feet of net oil pay in aggregate. The well confirmed the oil water contact in one of the Antan-1X well intervals and discovered oil in two deeper intervals that were not recorded by the Antan-1X well. The Antan-2X well has not been tested. As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves for Antan to be 15.1 MMbbl.

The Antan field is located in 40 m water depth and covers an area of approximately 1,620 acres (6.5 km^2) in the southern part of OML123. Subject to the receipt of necessary approvals, the Corporation has budgeted to commence facilities design for the Antan field in 2009.

Kita Marine (and extensions)

The Kita Marine field was discovered in 2005 and additional exploration and appraisal was conducted in 2006, 2007, and more recently in early 2008. The Corporation is now planning for full field development. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for Kita Marine to be 7.1 MMbbl and gross proved plus probable reserves to be 42.8 MMbbl.

In November 2005, the KTM-2 exploration well encountered a total of 100 ft of oil in a reservoir at a depth of 4,750 ftss which tested at 1,000 bbl/d of 28º API gravity oil. During 2006, two exploration wells were drilled on different blocks of Kita Marine; one well discovered oil and the other discovered gas. In the first quarter of 2008, the KTM-6 appraisal well encountered a total of 173 ft of oil in a reservoir at a depth of between 5,350 and 6,300 ftss. Flow tests were not performed, but pressure and fluid sample data indicate the presence of medium gravity oil, consistent with the 30° API Antan Blend produced from OML123. The Corporation is currently preparing development plans for the Kita Marine field.

Other Producing Fields (Akam, Bogi and Mimbo)

The Akam, Bogi and Mimbo fields were discovered in and have been producing since the 1980s. During 2008, combined production from two wells in these fields averaged 520 bbl/d. Oil gravity ranges between 19º and 37º API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for these fields to be 0.8 MMbbl and gross proved plus probable reserves to be 2.2 MMbbl. The Akam, Bogi and Mimbo fields are located in 10 to 40 m water depth and cover a combined area of approximately 1,700 acres (6.9 km^2). The Corporation did not conduct any drilling activity at these fields in 2008. No further drilling activity or significant capital expenditures are planned for the three fields in 2009.

Unappraised Discoveries and Exploration and Prospective Oil Resources

In addition to the existing fields, there are four unappraised discoveries in OML123 which are the Oron East gas discovery drilled in 1975, the Adanga West and Ebughu NE-A oil discoveries drilled in 2002 and the Adanga East oil discovery drilled in 2005. During 2008, the Corporation drilled one exploration well at the Adanga North Graben prospect. The Corporation has budgeted to drill one exploration well at Inagha West (IN-W) in 2009.

The Corporation continues to study the remaining exploration potential of OML123 based upon full 3D seismic survey and existing well data. The remaining exploration potential comprises near field potential clusters, which can be drilled from or which are readily accessible to existing production facilities, and prospect clusters which may require additional platforms and pipelines to connect to existing facilities. As at December 31, 2008 NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects on OML123 to be 340.5 MMbbl (71.4 MMbbl risked).

Budgeted Capital Expenditures

Capital expenditures for OML123 are budgeted to be $476 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion. The following table summarizes the budgeted capital expenditures for OML123:

	Development				
Licence / Category	**Drilling**	**Facilities & Other**	**Total**	**Exploration & Appraisal**	**Total**
	($million)	*($million)*	*($million)*	*($million)*	*($million)*
Infrastructure					
Adanga Redevelopment	—	33	33	—	33
Infrastructure upgrading	—	27	27	—	27
Others	—	15	15	—	15
Subtotal	—	75	75	—	75
Field Development					
Adanga	32	16	48	—	48
Adanga North	175	31	206	—	206
Oron (North and West)	63	4	67	—	67
Others	57	5	62	—	62
Subtotal	327	56	383	0	383
Exploration & appraisal	—	—	—	18	18
Total	**327**	**131**	**458**	**18**	**476**

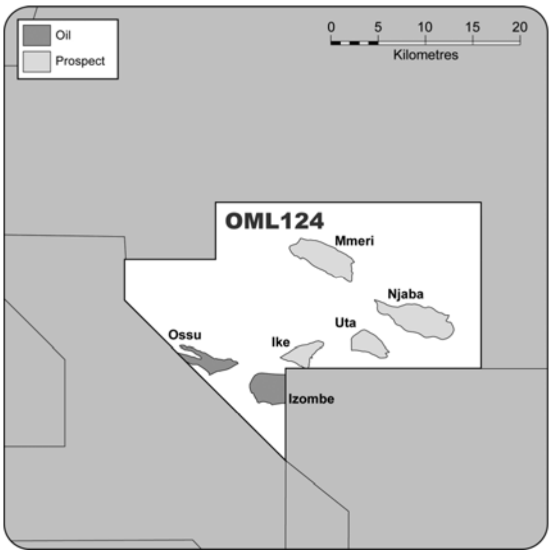
Columns may not add due to rounding

The budgeted capital expenditures are intended to fund a two-rig drilling program that includes:

- infill and extension drilling in the Adanga, Oron West, Ebughu and North Oron fields;
- continued development of the Adanga North Horst field, including water injection; and
- drilling one exploration well (Inagha West).

The budgeted capital expenditures are also intended to fund significant infrastructure investment to sustain future production, including upgrades to oil handling capabilities, the provision of water injection and gas gathering facilities, and facilities investment to aid in the continuing development of the Adanga, Adanga North Horst and Oron fields.

OML124



Overview

OML124 is the Corporation's smallest Nigerian property as measured by production. During 2008, OML124 produced an average of 7,230 bbl/d of oil from 19 wells. Oil gravity ranges between 18° and 42° API. As at December 31, 2008, the Corporation's gross proved reserves for OML124 were estimated to be 20.2 MMbbl and gross proved plus probable reserves to be 65.7 MMbbl. The Corporation expects its production from OML124 to average between 7,000 bbl/d and 9,000 bbl/d under its existing capital expenditure budget. A reduction of capital expenditures to correspond with an average Brent Crude price of \$40/bbl would result in total production from OML124 averaging between 5,000 bbl/d and 6,000 bbl/d in 2009.

OML124 is located onshore in Imo State, approximately 100 km north of Port Harcourt, and covers an area of 74,100 acres (300 km^2) on the northeast edge of the Niger Delta. OML124 contains two producing fields, Ossu and Izombe, and one recently discovered undeveloped field, Njaba. The Izombe field is adjacent to the Jisike field to the southeast in OML53 held by the Chevron/NNPC joint venture. OML124 also contains several identified exploration prospects, the most attractive of which are the Uta and Mmeri prospects in the southern and northern parts of the property, respectively.

Production and Reserves

The following table summarizes the Corporation's production and reserves in OML124.

		Average Oil Production		Gross Oil Reserves[1]		
Field	**Number of Oil Producing Wells[2]**	**December 2008** *(bbl/d)*	**12 Months Ended December 31, 2008** *(bbl/d)*	**Proved** *(MMbbl)*	**Proved plus Probable** *(MMbbl)*	**Proved plus Probable plus Possible** *(MMbbl)*
Izombe	7	1,540	2,240	8.6	10.2	17.1
Ossu	12	3,610	5,000	11.5	13.5	20.6
Njaba	-	-	-	-	42.0	67.5
Total	**19**	**5,150**	**7,230**	**20.2**	**65.7**	**105.2**

Columns may not add due to rounding

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) As at December 31, 2008.

Production Facilities

The Ossu and Izombe fields are operated as a common production area. Production facilities include the Izombe Flow Station, gas compressors, water injection pumps and three flow lines from Ossu to the Izombe Flow Station. The Corporation has an agreement with a Chevron/NNPC joint venture whereby crude oil produced from the Chevron/NNPC Jisike field is processed at the Izombe Flow Station in return for the payment of a tariff to Addax Petroleum. The Ossu, Izombe and Jisike crudes are all processed at the Izombe Flow Station and transported via an export pipeline to Ebocha. From Ebocha, the oil is transported through the Agip/NNPC joint venture's pipeline to their Brass River Terminal.

Addax Petroleum intends to cease flaring gas on OML124 in March 2009, at which time all of the associated natural gas being produced with the oil from OML124 will be re-injected to aid oil production. As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate contingent resources for gas and associated liquids for OML124 to be 377.0 Bcf and 22.8 MMbbl, respectively.

Fields

Izombe

The Izombe field, discovered in 1974 and producing since 1975, is Addax Petroleum's principal producing field in OML124. During 2008, Izombe produced an average of 2,250 bbl/d from seven wells with a watercut range of between 54 percent and 95 per cent. Oil gravity ranges between 31° and 40° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Izombe field to be 8.6 MMbbl and gross proved plus probable reserves to be 10.2 MMbbl.

The Izombe field is located in a relatively lightly populated dry land area at an elevation of 45 to 60 m above mean sea level, and covers an area of approximately 1,600 acres (6.4 km^2) in the southern part of OML124. The Corporation drilled two new production wells and worked over three existing wells in the Izombe field in 2008. In 2009, the Corporation has budgeted to perform maintenance on the Izombe facilities.

Ossu

The Ossu field was discovered in 1973 and has been producing since 1976. During 2008, Ossu produced an average of 5,000 bbl/d from 12 wells with a watercut range of between five percent and 95 per cent. Oil gravity ranges between 18° and 42° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Ossu field to be 11.5 MMbbl and gross proved plus probable reserves to be 13.5 MMbbl.

The Ossu field is located approximately 4 km to the west of the Izombe field at an elevation of 25 m above mean sea level in a drowned river valley susceptible to occasional seasonal flooding which limits the access to the field during the rainy season. The field covers an area of approximately 2,300 acres (9.3 km^2) in the south western part of OML124. In 2008, the Corporation drilled one production well and one appraisal well. The Corporation has not budgeted for any development drilling for the Ossu Field in 2009.

Njaba

The Njaba field was discovered in the fourth quarter of 2008 with the Njaba-2 well. The discovery was the first exploration well to be drilled in OML124 since 1986. The well encountered four oil-bearing reservoirs totalling 289 feet of gross oil column, including two main individual gross columns of 149 feet and 115 feet. As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves for the Njaba field to be 42.0 MMbbl.

In 2009, the Corporation may drill an additional appraisal well down-dip of the original Njaba discovery. Full field development planning could commence shortly thereafter.

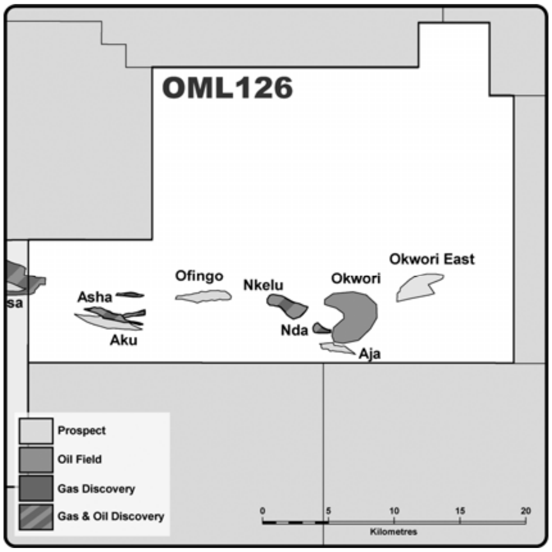
Unappraised Discoveries and Exploration

In 2002, the Corporation concluded a comprehensive acreage and prospect evaluation study based on 3D and 2D seismic surveys and existing well data. Several prospects with possible commercial potential were identified in OML124 including Uta and Mmeri. As at December 31, 2008 the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects on OML124 were estimated to be 110.4 MMbbl (9.3 MMbbl risked).

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures for OML124 are budgeted to be $16 million in 2009, including $11 million intended for facilities and $5 million intended for exploration and appraisal activities.

OML126



Overview

In 2006, Addax Petroleum received approval from NNPC for the conversion of OPL90 into OML126 effective November 2004. OML126 started production in March 2005, and is Addax Petroleum's newest producing property in Nigeria, having been the Corporation's largest greenfield development to date. During 2008, OML126 produced an average of 42,330 bbl/d of oil from eleven wells. Oil gravity ranges between 35° and 41° API. As at December 31, 2008, the Corporation's gross proved reserves for OML126 were estimated to be 32.6 MMbbl and gross proved plus probable reserves to be 42.9 MMbbl. The Corporation expects its production from OML126 to average between 38,000 bbl/d and 41,000 bbl/d under its existing capital expenditure budget. A reduction of capital expenditures to correspond with an average Brent Crude price of $40/bbl would result in total production from OML126 averaging between 38,000 bbl/d and 40,000 bbl/d in 2009.

OML126 is located 90 km offshore south of Port Harcourt, close to the edge of the continental shelf, in water depth averaging 130 m and covers an area of 178,300 acres (721.5 km^2). The southern half of OML126 has been completely surveyed by 3D seismic and contains two producing oil fields (Okwori and Nda), three undeveloped oil discoveries and four identified exploration prospects.

Production and Reserves

The following table summarizes the Corporation's reserves and production in OML126.

		Average Oil Production		**Gross Oil Reserves(1)**		
Field	**Number of Oil Producing Wells(2)**	**December 2008** *(bbl/d)*	**12 Months Ended December 31, 2008** *(bbl/d)*	**Proved** *(MMbbl)*	**Proved plus Probable** *(MMbbl)*	**Proved plus Probable plus Possible** *(MMbbl)*
Okwori	8	24,890	22,520	17.3	25.3	37.7
Nda	3	21,390	19,810	15.3	17.6	35.4
Total	**11**	**46,280**	**42,330**	**32.6**	**42.9**	**73.1**

Columns may not add due to rounding

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) As at December 31, 2008.

Production Facilities

The Okwori and Nda fields in OML126 are operated as a common development area. Individual wells in each field are connected to the FPSO Sendje Berge by individual sub-sea flow lines. At the OML126 FPSO, crude oil is processed to export specifications, stored and offloaded directly to ocean going tankers.

The OML126 FPSO has a nameplate processing capacity of 50 Mbbl/d of crude oil, a total liquids (oil and water) processing capacity of 60 Mbbl/d and a storage capacity of approximately 1.45 MMbbl of crude oil. The OML126 FPSO is under a time charter from Sendje Berge Ltd., a company within the Norwegian shipping group Bergesen now owned by Worldwide Shipping of Hong Kong. The primary term of the charter, which expired in February 2009, has extension periods of up to an additional four years at the Corporation's option. The Corporation has extended the term for two years with a right to make further extensions.

The production facilities at OML126 have been designed to accommodate additional production from future satellite developments, if planned exploration drilling results in commercial oil discoveries. The Corporation has budgeted for continuous drilling activity on OML126 including exploration drilling throughout most of 2009. The Corporation has also budgeted to complete sub-sea facilities and systems to tie in the development wells and to make upgrades to the FPSO in 2009.

Associated gas produced in OML126 is used as fuel gas and lift gas with the remainder being reinjected into the Nda reservoir in order to improve recovery. Addax Petroleum expects to cease flaring gas in OML126 in 2009. As at December 31, 2008, the Corporation's gross working interest best estimate contingent resources for gas and associated liquids for OML126 were estimated to be 91.7 Bcf and 1.5 MMbbl, respectively.

Fields

Okwori

The Okwori field, discovered in 1972 and appraised in 1973 by Occidental, was further appraised in the mid-1990s by a previous operator and declared commercial in 1996. Addax Petroleum began development of the Okwori field in July 2004 and commenced production from the Okwori field in March 2005. During 2008, the Okwori field produced an average of 22,520 bbl/d of oil from eight wells with an average watercut of 39 per cent. Oil gravity ranges between 34° and 41° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Okwori field were to be 17.3 MMbbl and gross proved plus probable reserves to be 25.3 MMbbl.

The Okwori field is located in 110 to 150 m water depth and covers approximately 2,700 acres (11 km^2) in the southern part of OML126. As of the end of December 2008, eight producing wells have been successfully drilled and tied in to the FPSO on the Okwori field. In 2008, the Corporation continued development of the Okwori field area, including drilling one new development well. In 2009, the Corporation has budgeted to drill a further four new development wells in order to complete Phase 3 of the Okwori field development plan.

When the OML126/137 PSC was awarded to Addax Petroleum in 1998, TOTAL, which held a 50 per cent farm-in interest in the previous operator's PSC, was given an option to retain a 50 per cent interest in the area. This option was replaced by a reimbursement agreement between TOTAL and Addax Petroleum dated October 24, 2000, whereby TOTAL was entitled to an eight per cent net profit interest in the Okwori field. This commitment was fulfilled in the fourth quarter of 2008.

Nda

The Nda field was discovered by Addax Petroleum in July 2004 and first production was achieved by the Corporation in July 2006. During 2008, the Nda field produced an average of 19,810 bbl/d of oil from three wells with watercut of two per cent. Oil gravity ranges between 35 ° and 36° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Nda field to be 15.3 MMbbl and gross proved plus probable reserves to be 17.6 MMbbl.

The Nda field is located adjacent to the Okwori field in a similar water depth and covers approximately 375 acres (1.5 km^2) in the southern part of OML126. The Nda field was developed as a subsea tie-back to the OPL126 FPSO. The Corporation drilled one production well and one gas injection well in 2008. The Corporation has budgeted to drill one new development well in 2009.

Unappraised Discoveries and Exploration

Addax Petroleum commenced its exploration on OML126 in 2004 by drilling one exploration commitment well. The exploration commitment well discovered the Nda field as discussed above. In 2006 and 2007, three unsuccessful exploration wells were drilled by the Corporation to test the Okporo, Sengi and Nda West prospects. In 2009, the Corporation has budgeted to acquire approximately 450 km^2 of 3D seismic over the northern portion of OML126 in order to identify additional prospects and plans to drill two exploration wells in OML126 (Okwori East and North East Okwori). As at December 31, 2008 NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects on OML126 to be 271.8 MMbbl (50.5 MMbbl risked).

Budgeted Capital Expenditures

Capital expenditures on OML126 are budgeted to be $436 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion. The following table summarizes the budgeted capital expenditures for OML126.

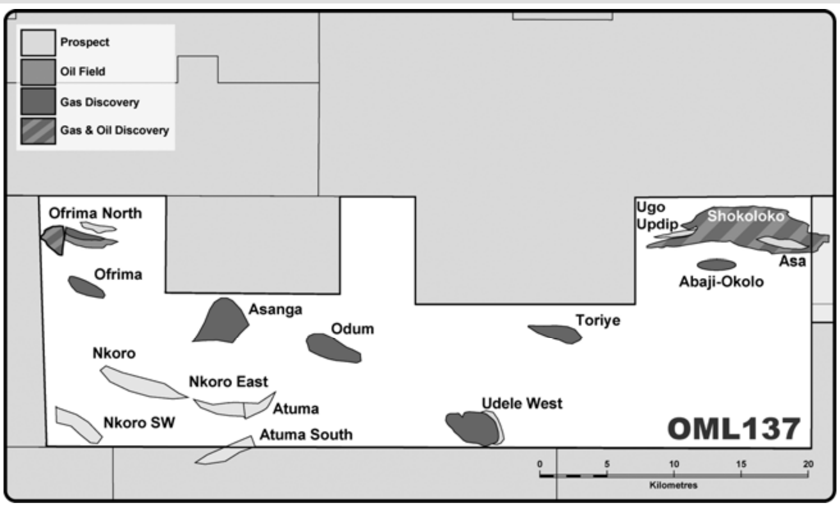
Licence/Category	Drilling ($million)	Development Facilities & Other ($million)	Total ($million)	Exploration, Appraisal & Other ($million)	Total ($million)
Field Development					
Okwori	172	160	332	-	332
Nda	50	-	50	-	50
subtotal	222	160	382	-	382
Exploration & Appraisal	-	-	-	54	54
Total	**222**	**160**	**382**	**54**	**436**

Columns may not add due to rounding

The budgeted capital expenditures are intended to fund a one-rig drilling program in OML126 that includes:

- continued development drilling and work overs in the Okwori and Nda fields;
- gas injection; and
- sub-sea facilities and FPSO topside modifications.

OML137



Overview

OML137 is an exploration and appraisal property, offshore Nigeria, next to the Corporation's OML126 property which is covered under the same PSC. As at December 31, 2008, the Corporation's gross probable reserves for OML137 were estimated to be 17.2 MMbbl.

OML137 is located 90 km offshore south of Port Harcourt, close to the edge of the continental shelf, in water depths ranging between 50 and 210 m and covers an area of 209,500 acres (848 km^2). OML137 was surveyed by 870 km^2 of 3D seismic in early 2006 and contains several potentially commercial natural gas discoveries (Shokoloko, Toriye, Odum, Asanga, Ofrima and Udele West), four identified oil prospects (Ofrima North, Atuma, Nkoro, and Asa) and a number of shallow and deep leads.

Production and Reserves

The following table summarizes the Corporation's reserves and production in OML137.

		Average Oil Production		Gross Oil Reserves(1)		
Field	Number of Oil Producing Wells(2)	December 2008 (bbl/d)	12 Months Ended December 31, 2008 (bbl/d)	Proved (MMbbl)	Proved plus Probable (MMbbl)	Proved plus Probable plus Possible (MMbbl)
Ofrima North	-	-	-	-	17.2	21.9
Total	**-**	**-**	**-**	**-**	**17.2**	**21.9**

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) As at December 31, 2008.

Production Facilities

To date, there has been no production from, and there are no production facilities on, OML137. Addax Petroleum believes that there are sufficient identified oil reserves and oil and gas resources at Ofrima North to justify a full field development and establish a new production hub for the Corporation but has budgeted additional appraisal drilling to facilitate planning. The current concept for Ofrima North contemplates a phased development which would include the development of the Ofrima North oil discovery using a subsea tie-back. As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate contingent resources for gas and associated liquids for OML137 to be 1,337.1 Bcf and 34.0 MMbbl, respectively.

Ofrima North Field

After booking first reserves on OML137 in 2007, the Corporation continued appraisal drilling activities in the Ofrima North area in 2008, including drilling the Ofrima-3 and Ofrima-3a wells, in the West and Main fault blocks of the Ofrima North discovery. The Ofrima-3 well discovered three hydrocarbon intervals in a gross hydrocarbon column of 72 feet, comprising 30 feet of light oil overlain by 42 feet of rich gas, a gross liquids-rich gas column of 50 feet and a gross light oil column of 32 feet. The Ofrima-3a well confirmed the western continuity of the H42 oil reservoir within the Main fault block and a common oil water contact with the Ofrima-2 well, located approximately one kilometre to the east. The Corporation has budgeted to continue its appraisal drilling activity in the Ofrima North area, including drilling one well in 2009, and is preparing a development plan for the field. As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves for the Ofrima North Field to be 17.2 MMbbl.

Unappraised Discoveries, Exploration and Prospective Oil Resources

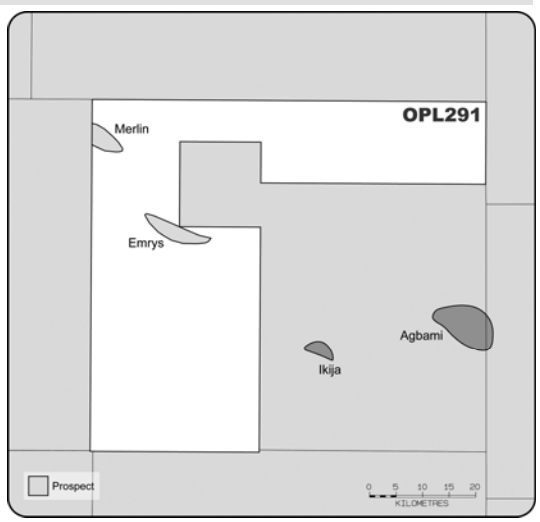
Exploration in OML137 was initiated by Occidental, which drilled the Shokoloko discovery well in 1972. This well tested at an oil rate of 6.1 Mbbl/d. Occidental relinquished the block in 1975 following the drilling of three additional exploration wells, one of which encountered natural gas. Commencing in 1979, Elf drilled three mainly natural gas bearing exploration wells but then relinquished OML137 in 1983. Addax Petroleum commenced its exploration on OML137 in 2004 by drilling one exploration commitment well. The exploration well drilled by the Corporation in OML137 found two small accumulations of non-associated natural gas. The Corporation's prospect portfolio consists mainly of medium to large natural gas structures as well as three identified oil prospects. During 2006, the Corporation processed a 870 km^2 3D seismic survey and identified several further exploration drilling opportunities as a result. As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects on OML137 to be 253.5 MMbbl (112.0 MMbbl risked).

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures on OML137 are budgeted to be $58 million in 2009 which are intended to fund the drilling of one further exploration and appraisal well.

OPL291

Overview



The Corporation acquired a 72.5 per cent interest in, and operatorship of, OPL291 in October 2006 from Starcrest, who retained the remaining 27.5 per cent interest. OPL 291 is a highly prospective deepwater exploration block offshore Nigeria.

OPL291 is located approximately 130 km off the Nigerian coast, where the water depth ranges from approximately 1,000 to 2,300 m and covers a gross area of 318,100 acres (1,287 km^2). OPL291 is immediately adjacent to OML127 (to the east) which contains the Agbami and Ikija fields, operated by Chevron, and OPL242 (to the west) operated by Devon Energy Corporation.

Under the terms of the PSC between Addax Petroleum, Starcrest and NNPC, Addax Petroleum and Starcrest (i) paid a PSC signature bonus to NNPC of $55 million, (ii) agreed to undertake an initial investment of $75 million covering an initial work commitment which comprises the acquisition of 3D seismic and drilling one well, and (iii) entered into a Memorandum of Understanding with NNPC to undertake an investment in an independent power project which would be developed with natural gas from a commercial development in OPL291 and on agreement with NNPC regarding the technical and commercial arrangements should the independent power project proceed.

Pursuant to the farm-in agreement with Starcrest, Addax Petroleum (i) paid 100 per cent of the OPL291 PSC signature bonus of $55 million to the Nigerian government, (ii) paid a farm-in fee of $35 million to Starcrest, and (iii) will pay Starcrest's share of OPL291 exploration and development costs which will be reimbursed to Addax Petroleum from Starcrest's share of production revenues from OPL291.

Production and Reserves

There has been no production to date and no reserves have been booked for OPL291.

Exploration and Prospective Oil Resources

The Corporation acquired 2D seismic data which covers the majority of the OPL291 licence area and has identified two potentially significant prospects, Merlin and Emrys, as well as a number of leads from this data. During the second half of 2008, the Corporation acquired approximately 1,500 km^2 of 3D seismic over the northern portion of OPL291 in order to further define the Merlin and Emrys prospects as well as adding to the licence area's prospect inventory. As at December 31, 2008, the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects on OPL291 were estimated to be 566.0 MMbbl (187.6 MMbbl risked).

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures on OPL291 are budgeted to be $15 million in 2009, intended for the completion of the 3D seismic survey.

OPL227

Overview

OPL227 is an exploration and appraisal property, offshore Nigeria, and accounts for the largest surface area of any of the Corporation's properties in Nigeria. In the first half of 2008, the Corporation acquired a 40 per cent interest in OPL227, and is awaiting receipt of the formal deed of assignment. Its co-participants in the licence area are Express and PPI, with 39 per cent and 21 per cent interests, respectively. Express will be the operator, while Addax Petroleum will act as technical advisor. In return, Addax Petroleum has paid a farm-in fee to Express and PPI and a signature bonus to the Federal Government of Nigeria, and will be obligated to fund 80 per cent of the work program comprising a minimum of 500 km^2 of 3D seismic acquisition during the exploration phase. Express will fund the remaining 20 per cent. Addax Petroleum will also initially fund 80 per cent of all capital and operating costs on OPL227 and will be entitled to a higher than pro-rata share of the net production from OPL227 until all capital costs have been recovered, after which the parties will be entitled to their pro-rata share of production.

OPL227 is located approximately 7 km offshore Nigeria, in shallow water, and covers a gross area of 210,300 acres (851 km^2). OPL227 is adjacent to and to the north-east of OML79, operated by Shell, and which contains the EA field, reported to contain approximately 350 MMbbl of remaining recoverable oil.

Production and Reserves

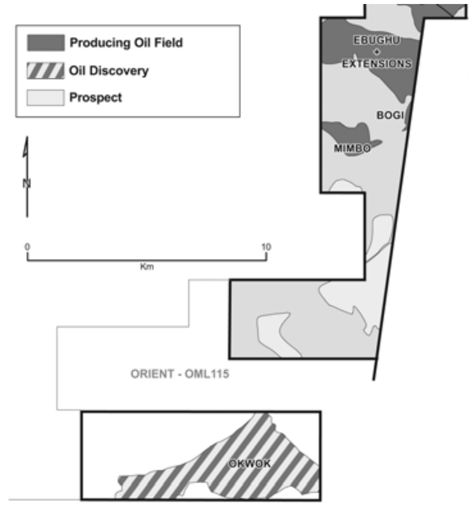
There has been no production to date and no reserves have been booked for OPL227.

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures on OPL227 are budgeted to be $2 million in 2009, intended to fund appraisal activity.

Okwok

Overview



The Okwok property is a shallow water potential development opportunity offshore Nigeria in which the Corporation acquired a 40 per cent interest from Oriental Energy in July 2006. As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves for Okwok to be 7.9 MMbbl.

The Okwok property covers a gross area of 22,500 acres (91 km^2) and is located approximately 45 km off the Nigeria coast in 35 to 50 m water depth due south of the town of Calabar. The Okwok property is within ExxonMobil's licence area OML67, immediately to the south of OML123.

In late 2000, the governments of Nigeria and Equatorial Guinea concluded a maritime boundary treaty that removed 62 km^2 from an OML held by Oriental Energy that became part of Equatorial Guinea's Block B, the main beneficiary of which was ExxonMobil. Oriental Energy successfully petitioned the Nigerian government for compensation and received a compensation area in ExxonMobil's OML67 that includes the Okwok property.

Addax Petroleum entered into the Oriental Joint Venture Agreement in September 2005, acquiring a 40 per cent interest in the Okwok property and conducting operations in its capacity as technical advisor. The Oriental Joint Venture Agreement became effective in July 2006. Pursuant to the Oriental Joint Venture Agreement, Addax Petroleum made a cash payment of $35 million to Oriental Energy and will initially fund all capital and operating costs. During the cost recovery period, the Corporation will be entitled to 80 per cent of production from the Okwok property until all capital costs have been recovered by the Corporation after which Addax Petroleum and Oriental Energy will be entitled to their pro rata share of production. As broker of the Oriental Joint Venture Agreement, Sovereign Oil & Gas Company II LLC will receive an overriding royalty interest of one per cent of all production from the Okwok property.

Production and Reserves

As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves to be 7.9 MMbbl. There has been no production to date; however, the Corporation is continuing to review development plans for the licence area.

Field Description

The Okwok field is located south of and adjacent to OML123, in water depth of approximately 50 m and covers a gross area of 22,500 acres (91 km^2). The Okwok field was discovered in 1967 by ExxonMobil, with the first well encountering a gross oil bearing interval of approximately 70 ft in two main zones. The second well was drilled in 1968 to appraise a fault block to the east of the discovery well and encountered a gross oil bearing interval of approximately 150 ft. Two further wells have been drilled in the immediate area, the most recent of which was drilled by Oriental Energy and ConocoPhillips in 1993. Both of these wells were drilled on the edge of the main Okwok structure and while they only encountered minimal hydrocarbons they are useful in assisting to delineate the structure. None of these wells were production tested. The Okwok field has been surveyed by two 3D seismic surveys, the most recent of which was in 2004.

A 2006 appraisal program for the Okwok field tested the commercial potential of the field by drilling three wells and one sidetrack well. Two of the wells were flow tested during the exploration and appraisal program. The first well test produced at a rate of 400 bbl/d of light 32° API oil; however, the true flow potential of the well was not reached because of sand control problems. The second well test produced at a rate of 1,220 bbl/d of medium 26° API oil. Both wells are currently suspended for potential tie-back to production facilities. In 2008, Addax Petroleum and Oriental Energy continued to incorporate well data, oil properties and flow test data from this exploration and appraisal program into existing geological and engineering models. The new information will be used to evaluate the future work program which the Corporation anticipates may include further appraisal drilling. These efforts are expected to continue in 2009.

Budgeted Capital Expenditures

Capital expenditures on Okwok are budgeted to be $4 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion, intended to fund further appraisal activity.

Oil Sales Arrangements

In 2008, Addax Energy purchased the Corporation's entitlement of crude oil from OML123, OML124 and OML126 pursuant to the Crude Oil Supply Agreements. Crude oil produced from OML123 is exported from the Antan Terminal and sold as Antan Blend. The Antan Blend includes oil delivered by the OML114 Parties and may, in the future, include oil production from the Okwok property in the event that it is developed by Addax Petroleum. Crude oil produced from OML124 is transported by pipeline to the Brass River Terminal and commingled with crude oil from several third party oil fields. The resulting blend, known as Brass River Blend, is exported and sold at international prices. Crude oil produced from OML126 is exported from the Okwori Terminal and sold as Okwori Blend.

Addax Petroleum Crude Oil Premium/(Discount) to Brent Crude (Volume Weighted)(1)

	Year ended December 31,		
	2008	**2007**	**2006**
Sales and Marketing Volumes (MMbbl)			
Antan Blend	20.9	20.2	18.5
Brass River Blend	2.7	2.9	1.3
Okwori Blend	15.1	15.9	11.2
Dated Brent Crude Price ($/bbl)	96.99	72.52	65.11
Addax Petroleum Average Realized Prices ($/bbl)			
Antan Blend	92.64	71.74	61.71
Brass River Blend	92.42	76.61	66.90
Okwori Blend	97.52	75.39	66.34
Premium/(Discount) to Brent Crude ($/bbl)			
Antan Blend	(4.43)	(2.15)	(3.76)
Brass River Blend	1.59	1.02	1.32
Okwori Blend	2.74	3.53	1.27

Note:

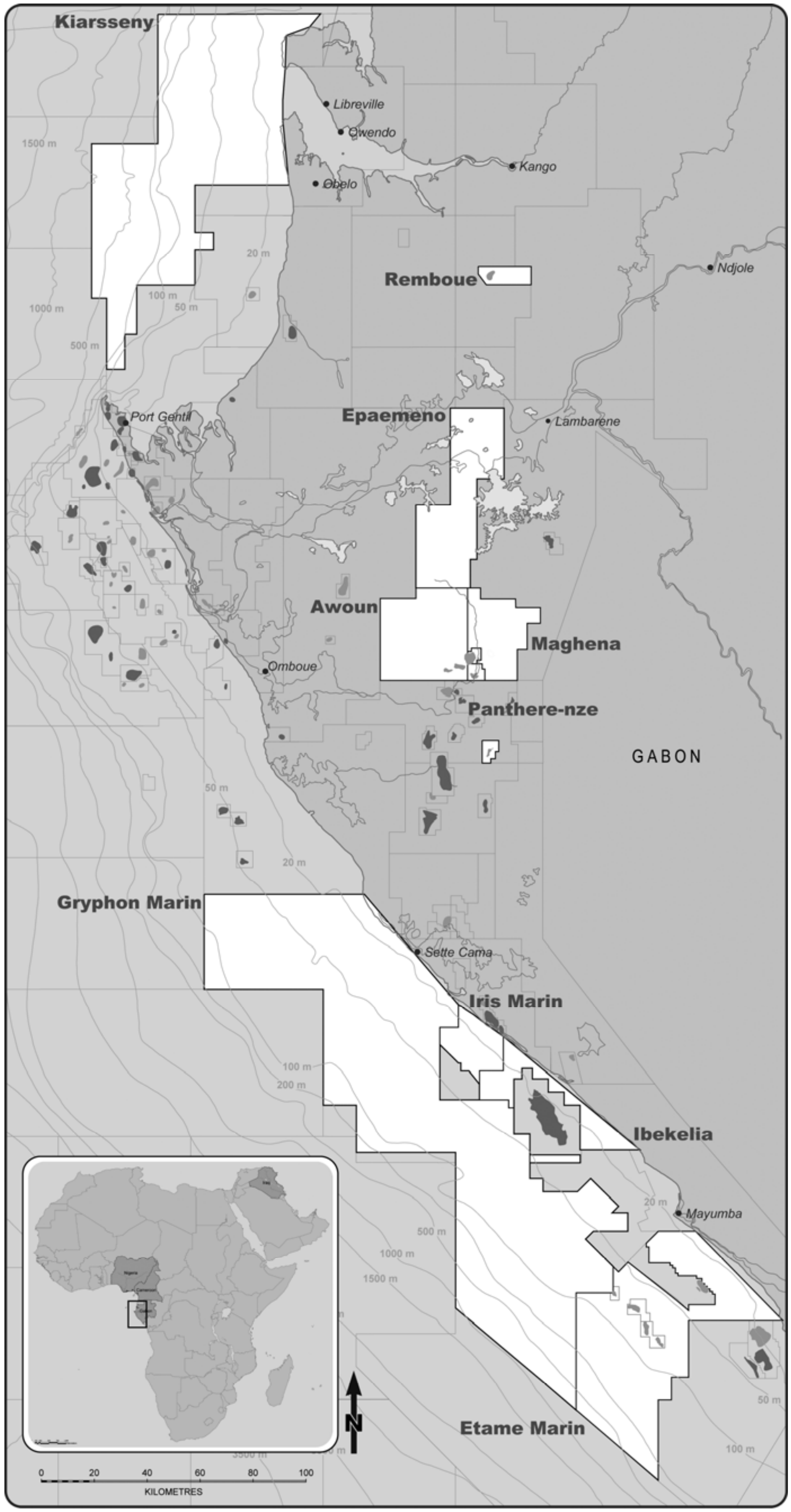
(1) Premium/(Discount) to Brent Crude are reported on a volume weighted basis for both the crude in question and Brent Crude, whereas Dated Brent Crude prices are reported as averages of monthly values for the period. Accordingly, the difference between the reported average realized petroleum prices and Dated Brent Crude prices may not correspond to the Premium/(Discount) to Brent Crude.

Gabon

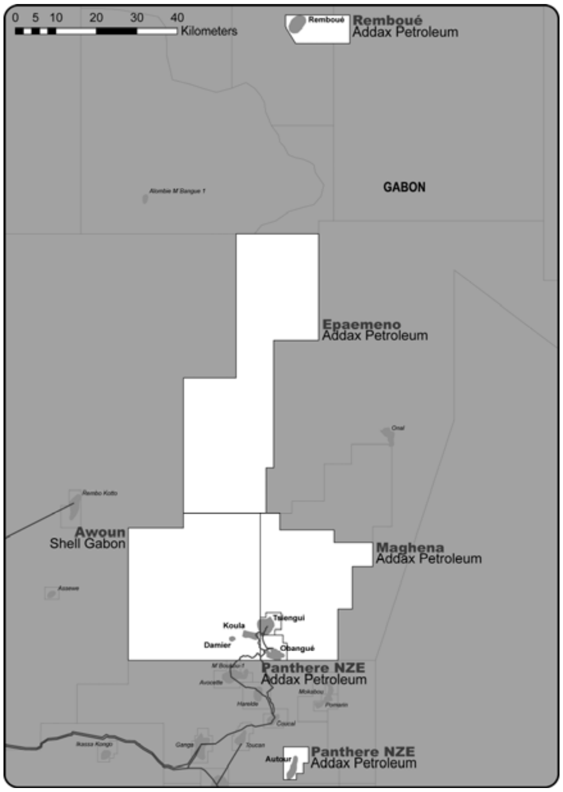
Within Gabon, Addax Petroleum has various interests in five PSCs covering five onshore licence areas and four PSCs and a technical evaluation agreement covering five offshore licence areas. The Corporation currently has six producing fields and expects two additional fields to commence production in 2009.

In 2008, the Corporation has capital expenditures totalling $462 million in Gabon (including acquisitions), and produced an average of 28,470 bbl/d from its Gabon properties. In 2009, the Corporation has budgeted capital expenditures of $425 million with associate total production from Gabon averaging between 31,000 bbl/d and 34,000 bbl/d. This budgeted total capital expenditure amount is consistent with Addax Petroleum's philosophy of funding capital expenditures from internally generated cash flow and has been estimated using an average Brent Crude price of $60/bbl. Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, the Corporation will reduce capital expenditures to ensure that total capital expenditures continue to be funded by internally generated cash flow. An average Brent Crude price of $40/bbl would result in a reduction of spending to approximately $400 million, with no change to total production guidance for Gabon in 2009.

As at December 31, 2008, the Corporation's gross proved reserves for Gabon were estimated to be 66.7 MMbbl, gross proved plus probable reserves to be 103.3 MMbbl and gross proved plus probable plus possible reserves to be 127.0 MMbbl.



Onshore Properties



Overview

Addax Petroleum's onshore properties contribute the bulk of the production and operations in Gabon. During 2008, the Gabon onshore properties produced a combined average of 21,800 bbl/d of oil net to Addax Petroleum. Oil gravity ranges between 31° and 36° API. As at December 31, 2008, the Corporation's gross proved reserves for the Gabon onshore properties were estimated to be 56.9 MMbbl and gross proved plus probable reserves to be 86.4 MMbbl. The Corporation expects its working interest production from the Gabon onshore properties to average between 24,000 bbl/d and 28,000 bbl/d in 2009 under its existing capital expenditure budget. A reduction of capital expenditures to correspond with an average Brent Crude price of $40/bbl would result in total production from the Gabon onshore properties averaging between 23,000 bbl/d and 27,000 bbl/d in 2009.

The Gabon onshore properties cumulatively cover a gross area of 830,100 acres (3,362 km^2) and consist of five licence areas: Maghena, Panthere NZE, Awoun, Remboué and Epaemeno. These licence areas contain four producing oil fields (Tsiengui, Obangue, Remboué and Tsiengui West), one oil field under development (Koula), and two undeveloped oil fields (Autour and Damier).

Production and Reserves

The following table summarizes the Corporation's production and reserves in the Gabon onshore properties:

			Average Oil Production		Gross Oil Reserves(1)		
Licence	**Field**	**Number of Oil Producing Wells(2)**	**December 2008** *(bbl/d)*	**12 Months Ended December 31, 2008** *(bbl/d)*	**Proved** *(MMbbl)*	**Proved plus Probable** *(MMbbl)*	**Proved plus Probable plus Possible** *(MMbbl)*
Maghena	Tsiengui	31	18,000	18,110	24.9	29.0	31.8
Panthere NZE	Obangue	5	1,350	1,610	17.9	28.5	31.3
	Autour	-	-	-	-	5.4	9.9
Awoun	Koula	-	-	-	9.7	12.9	14.5
	Tsiengui West	5	3,030	1,480	3.0	4.1	4.4
	Damier	-	-	-	-	0.5	0.7
Remboué	Remboué	6	360	590	1.5	6.1	7.2
Total		**47**	**22,740**	**21,800**	**56.9**	**86.3**	**99.9**

Columns may not add up due to rounding

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) As at December 31, 2008.

Licences and Fields

Tsiengui Field (Maghena licence)

The Tsiengui field is Addax Petroleum's principal onshore producing and development property in Gabon. The field is located within the Maghena licence area and is immediately adjacent to Addax Petroleum's Panthere NZE licence area. Addax Petroleum operates and holds a 92.5 per cent interest in the Maghena licence. The Maghena licence area is approximately 100 km southeast of the coastal city of Port Gentil and covers a gross area of 162,400 acres (657 km^2).

In 2008, the Corporation's production from Tsiengui averaged 18,110 bbl/d from 31 wells with an average watercut of 30 per cent. Oil gravity averaged 33° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Tsiengui field to be 24.9 MMbbl and gross proved plus probable reserves to be 29.0 MMbbl.

The previous operator confirmed a significant oil discovery on the Tsiengui prospect with its second exploration commitment well in 2004. During 2008, one gas injection well and 14 horizontal development wells were successfully drilled and completed on the Tsiengui field, bringing the total number of producing wells to 31. Oil from the Tsiengui field is produced from both the Gamba and Dentale formations. Based on the current reservoir model, Addax Petroleum anticipates that approximately 45 additional wells will be required to further develop the Tsiengui field, three of which are budgeted to be drilled in 2009, including one water injection well and one gas injection well.

Oil production from the Tsiengui field is processed and exported together with oil production from the Obangue field through a central production facility which was commissioned by Addax Petroleum in November 2006. The production and export system is comprised of a 30,000 bbl/d central production facility at the Tsiengui field, a 30-kilometre, 10-inch pipeline from Tsiengui to the Coucal facility, which is operated by TOTAL Gabon, and additional heating and pumping capacity at Coucal. The system then ties into the main northern export trunk line and the export terminal at Cap Lopez in Port Gentil, Gabon. The production and export system has a current export capacity of 30,000 bbl/d following the installation of additional heating and pumping facilities at Coucal in 2007. As Addax Petroleum expects to continue growing production from onshore Gabon beyond this current export capacity, the Corporation has commenced the extension of its export system, including a new 38-kilometre, 12-inch pipeline from Coucal to Rabi which will allow for further increases in production by availing of spare capacity through the Shell operated Rabi station. The Rabi station then ties into the main southern export trunk line and the export terminal at Gamba. The new export system will have capacity of 50,000 bbl/d and the Corporation expects it to be commissioned in the second quarter of 2009.

Obangue Field (Panthere NZE licence)

The Obangue field, discovered in 1988 and producing since 1998, is Addax Petroleum's second largest onshore producing property in Gabon. The Panthere NZE licence area contains the Obangue field and is immediately adjacent to Addax Petroleum's Maghena licence area. Addax Petroleum operates and holds a 92.5 per cent interest in the Panthere NZE licence. The Panthere NZE licence area is approximately 110 km southeast of the coastal city of Port Gentil and covers a gross area of 29,700 acres (120 km^2).

In 2008, the Corporation's production from Obangue averaged 1,610 bbl/d from five wells with an average watercut of 65 per cent. Oil gravity averaged 31° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Obangue field to be 17.9 MMbbl and gross proved plus probable reserves to be 28.5 MMbbl.

There was no development drilling during 2008, and the total number of producing wells remained at five. Oil from the Obangue field is produced from both the Gamba and Dentale formations. Based on the current reservoir model, Addax Petroleum anticipates that at least an additional 60 wells will be required to further develop the Obangue field, of which Addax Petroleum has budgeted to drill 17 additional horizontal development wells and one gas injection well in 2009.

Oil production from the Obangue field is processed and exported together with oil production from the Tsiengui field through the new central production facility which will be commissioned by Addax Petroleum in the first quarter of 2009.

Autour Field (Panthere NZE licence)

The Autour field is an undeveloped oil field within the Panthere NZE licence area. The Corporation drilled an appraisal well at the Autour field in 2007 which resulted in the addition of 5.4 MMbbl probable reserves in that year. No additional activity was undertaken in 2008. One development/appraisal well is budgeted for 2009, which is being drilled in the first quarter of 2009**.** As at December 31, 2008, NSAI estimates the Corporation's gross probable reserves for the Autour field to be 5.4 MMbbl.

Tsiengui West, Koula and Damier Fields (Awoun licence)

The Awoun licence contains the Tsiengui West, Koula and Damier oil fields. Addax Petroleum holds a 40.0 per cent interest in the Awoun licence area which is immediately adjacent to Addax Petroleum's Maghena licence area. The Awoun licence is operated by Shell Gabon. The Awoun licence area is approximately 80 km southeast of the coastal city of Port Gentil and covers a gross area of approximately 274,800 acres (1,112 km^2).

The Tsiengui West field is an extension of the Corporation's main Tsiengui field in the Maghena licence area, and came on-stream in December 2007. In 2008, the Corporation's production from Tsiengui West averaged 1,480 bbl/d from five wells with an average watercut of less than one per cent. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Tsiengui West field to be 3.0 MMbbl and gross proved plus probable reserves to be 4.1 MMbbl. Based on the current reservoir model, Addax Petroleum anticipates that at least nine additional wells will be required to further develop the Tsiengui West field, including four that are budgeted to be drilled in 2009.

The Koula and Damier fields were both discovered in 2004. In 2006, the operator drilled an appraisal well at Koula to confirm the extent of the field. In late 2007, the operator drilled the first of the three development wells at the Koula field, with first production expected to commence in the second half of 2009. The Corporation has budgeted to complete the Koula facilities in 2009. The appraisal of the Damier discovery was completed during the second quarter of 2005 and the field remains undeveloped. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Koula and Damier fields to be 9.7 MMbbl and gross proved plus probable reserves to be 13.4 MMbbl.

Remboué Field (Remboué licence)

The Remboué field, discovered in 1991 and producing since 2001, is Addax Petroleum's smallest onshore producing property in Gabon. The Remboué licence area contains the Remboué field. Addax Petroleum operates and holds a 92.0 per cent interest in the Remboué licence area and also carries the costs for the remaining 8.0 per cent interest. The Remboué licence area is located approximately 75 km southeast of the coastal city of Libreville and covers an area of approximately 32,200 acres (130 km^2).

In 2008, the Corporation's production from Remboué averaged 590 bbl/d from six wells with an average watercut of 43 per cent. Oil gravity averaged 36° API. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Remboué field to be 1.5 MMbbl and gross proved plus probable reserves to be 6.1 MMbbl.

There is a single train of processing facilities in the Remboué field and 25,000 bbl of tank storage. The Remboué export system is entirely marine with export loads shipped by barge from the field to an offshore storage vessel, and subsequently sold directly to international markets. There was no drilling activity at Remboué in 2008 and Addax Petroleum has budgeted for up to two work overs in Remboué in 2009.

Unappraised Discoveries, Exploration and Prospective Oil Resources

The Corporation's onshore Gabon properties comprise a large acreage position in the proven Gamba play fairway. Much of Addax Petroleum's acreage is under-explored with 2D seismic coverage inherited from previous operators but which is too sparse to identify typical fields discovered nearby, such as Koula and Damier. Following the acquisition of approximately 126 km^2 of seismic on the southern end of the Maghena and Awoun licence areas in 2007, Addax Petroleum continued to conduct an infill 2D program on the Maghena and Epaemeno licence areas during 2008. This is expected to allow for processing and interpretation with the budgeted drilling of two exploration prospects in 2009. In late 2008, the Corporation drilled the Andok prospect in the Maghena licence area which encountered hydrocarbon shows but was unsuccessful. Based on the current prospect inventory, as at December 31, 2008 NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects in the Gabon onshore properties to be 98.7 MMbbl (17.9 MMbbl risked).

Budgeted Capital Expenditures

Capital expenditures for the Corporation's onshore Gabon properties are budgeted to be $365 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion. The following table summarizes the budgeted capital expenditures for the Corporation's onshore Gabon properties.

	Development				
Licence / Category	**Drilling** *($million)*	**Facilities & Other** *($million)*	**Total** *($million)*	**Exploration & Appraisal** *($million)*	**Total** *($million)*
Field Development					
Tsiengui	20	81	101	—	101
Obangue	122	53	175	—	175
Koula	—	12	12	—	12
Tsengui West	22	—	22		22
Autour	8	3	11	—	11
Remboué	—	2	2	—	2
Subtotal	172	151	323	0	323
Exploration & appraisal					
Maghena	—	—	—	24	24
Epaemeno	—	—	—	10	19
Awoun	—	—	—	8	8
Subtotal	—	—	—	42	42
Total	**172**	**151**	**323**	**42**	**365**

The budgeted capital expenditures are intended to fund a four-rig drilling program that includes:

- ongoing development drilling at the Tsiengui, Autour and Obangue fields;
- development drilling at the Tsengui West field in the Awoun licence area;
- drilling one exploration well in the Maghena licence area and one in the Epaemeno licence area; and
- Koula field development and completion of Coucal/Rabi export pipeline.

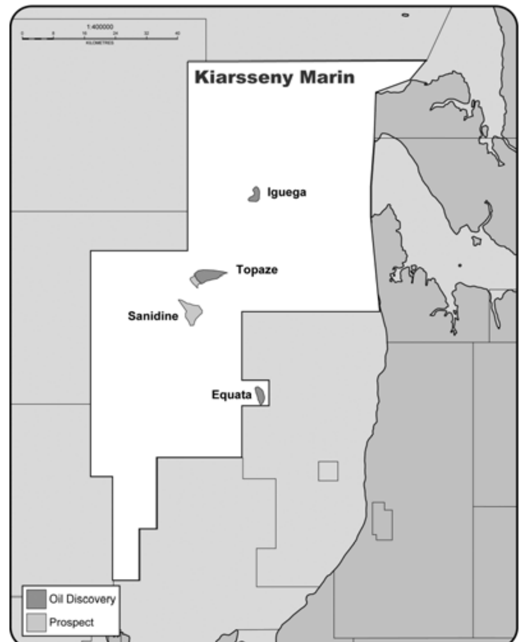
The budgeted capital expenditures are also intended to fund significant infrastructure investment to accommodate growth in future production, including the upgrading of the Tsiengui production facilities, the installation of a new central production facility at Obangue and Koula as well as the new 38-kilometre, 12-inch Coucal to Rabi pipeline. The Corporation has also budgeted for seismic data acquisition in the Awoun, Epaemeno and Maghena licence areas.

Offshore Properties

Overview

The Gabon offshore properties are a combination of production, development and exploration properties. Addax Petroleum operates the Gryphon Marin and Iris Marin licence areas, while the other licence areas are operated by other companies. In 2008, the Corporation's working interest production from its offshore properties averaged 6,680 bbl/d from six wells with an average watercut of 26 per cent. Oil gravity averaged 36° API. As at December 31, 2008, NSAI estimates gross proved reserves for the Gabon offshore properties to be 9.8 MMbbl and gross proved plus probable reserves to be 16.9 MMbbl. The Corporation expects its working interest production from the Gabon offshore properties to average between 6,000 bbl/d and 7,000 bbl/d in 2009 under its existing capital expenditure budget. Based on performance to date in 2009, the Corporation now expects its working interest total production from the Gabon offshore properties averaging between 7,000 bbl/d and 8,000 bbl/d in 2009.

The Gabon offshore properties cumulatively cover a gross area of approximately 5,610,900 acres (22,707 km^2) and contain two producing oil fields (Etame and Avouma), one oil field under development (Ebouri) and one undeveloped oil field (North Tchibala), all within the Etame Marin licence area. There are also several unappraised oil discoveries and identified prospects.



Production and Reserves

The following table summarizes the production and reserves in the Gabon offshore properties:

			Average Oil Production		Gross Oil Reserves[1]		
Licence	**Field**	**Number of Oil Producing Wells[2]**	**December 2008**	**12 Months Ended December 31, 2008**	**Proved**	**Proved plus Probable**	**Proved plus Probable plus Possible**
			(bbl/d)	*(bbl/d)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Etame Marin	Etame	4	3,260	3,500	4.2	7.6	8.8
	Avouma	2	3,000	3,180	1.6	2.7	2.9
	Ebouri	–	–	–	4.0	6.7	10.9
	North Tchibala	–	–	–	–	–	4.4
Total		**6**	**6,260**	**6,680**	**9.8**	**16.9**	**27.1**

Columns may not add due to rounding

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under “Forecast Prices and Costs Case”.

(2) As at December 31, 2008.

Production Facilities

The Etame, Avouma, Ebouri and North Tchibala fields in the Etame Marin licence area are operated as a common development area. Individual sub-sea wells in each field are or will be connected to the Etame Marin FPSO, called the FPSO Petróleo Nautipa, by individual sub-sea flow lines. At the Etame Marin FPSO, crude oil is processed to export specifications, stored and offloaded directly to ocean-going tankers. The Etame Marin FPSO has nameplate processing capacity of 30 Mbbl/d of liquids (oil and water) and a storage capacity of approximately 1.1 MMbbl of crude oil. The Etame Marin FPSO is under a time charter from a consortium made up of Fred Olsen Production A.S. and Prosafe Production Ltd. The term of the charter is for a five-year period that expires in September 2012.

Fields

Etame Field (Etame Marin licence)

The Etame field, in the Etame Marin licence area, is Addax Petroleum’s principal offshore producing property in Gabon. Addax Petroleum holds a 31.36 per cent interest in the Etame Marin licence area, which is operated by VAALCO. The Etame Marin licence area covers a gross area of approximately 759,600 acres (3,074 km^2) in the Gabon Basin, offshore southern Gabon. Water depths in the licence area range from zero to more than 500 m from the north to south.

In 2008, the Corporation’s share of production from the Etame field averaged 3,500 bbl/d from four wells with an average watercut of 25 per cent. Oil gravity averaged 36° API. As at December 31, 2008, NSAI estimates the Corporation’s gross proved reserves for the Etame field to be 4.2 MMbbl and gross proved plus probable reserves to be 7.6 MMbbl.

The Etame field is in water depths of approximately 75 to 80 m and it currently has four wells producing from the Gamba reservoir. There was no development drilling activity at the Etame field during 2008. One production well is budgeted for 2009.

Avouma Field (Etame Marin licence)

The Avouma field is also in the Etame Marin licence area and has been producing since 2007. In 2008, the Corporation’s production from Avouma averaged 3,180 bbl/d from two wells with an average watercut of 20 per cent. Oil gravity averaged 36° API. As at December 31, 2008, NSAI estimates the Corporation’s gross proved reserves for the Avouma field to be 1.6 MMbbl and gross proved plus probable reserves to be 2.7 MMbbl.

The Avouma field is approximately 17 km southeast of the Corporation’s producing Etame field. The oil flowing from the Avouma platform is being loaded aboard the Etame Marin FPSO via a 16 km long pipeline. Construction of the last phase of the pipeline was completed in early 2007 with the installation of a flexible riser to connect the pipeline to the Etame Marin FPSO. No development drilling is budgeted at Avouma in 2009.

Ebouri Field (Etame Marin Licence)

The Ebouri field was discovered in 2003 and is approximately 18 km northwest of the Corporation's producing Etame field. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Ebouri field to be 4.0 MMbbl and gross proved plus probable reserves to be 6.7 MMbbl.

Approval for the development of the Ebouri field was received from the Gabonese authorities in September 2006. In late 2008 and early 2009, the Corporation drilled two appraisal and development wells (Ebouri 2H and 3H, respectively). The Ebouri 2H well has been producing 1,500 bbl/d net to the Corporation since late January 2009. Installation of a jacket and a pipeline from the Ebouri field to the Etame Marin FPSO was completed in 2008. The Corporation has not budgeted any further development wells at Ebouri in 2009.

Unappraised Discoveries, Exploration and Prospective Oil Resources

As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects in the Gabon offshore licence areas to be 122.3 MMbbl (43.1 MMbbl risked).

Etame Marin licence

In 2009 the Corporation has budgeted to drill one exploration well in the Etame Marin licence area near the producing Etame field (Etame SE). An unsuccessful exploration well was drilled by the operator at the beginning of 2009 at N Etame.

Kiarsseny licence

The Kiarsseny licence area covers a gross area of approximately 1,344,900 acres (5,443 km^2) and is adjacent to shore in the Port Gentil Basin in water depths of up to 800 m. It contains three oil discoveries and additional exploration potential. There are 2,643 km^2 of 3D seismic data, 12,000 km of 2D seismic data and 25 wells in the Kiarsseny licence area. The Port Gentil Basin contains a prolific hydrocarbon system. The majority of the producing reservoirs are sandstones with good porosities and permeabilities. Oil gravities from major oil fields vary from 20° to 47° API.

The Kiarsseny PSC is currently in its second exploration phase of three years, ending March 2010, and has a one well commitment. The first commitment well was drilled by Tullow Oil and Addax Petroleum in February 2004 to appraise the Topaze South structure and subsequently a side-track was drilled into the central Topaze compartment. The well failed to prove up sufficient reservoir development in both instances and was therefore abandoned. The second commitment well was drilled by Tullow Oil in late 2005. The well was unsuccessful as the results indicated likely compartmentalization of the structure which would make the development sub-commercial. The well has been plugged and abandoned. The operator is currently performing the technical analysis to select the prospect to be drilled in the second exploration phase and drilling is expected to take place in 2010.

Iris Marin licence

Addax Petroleum holds a 51.33 per cent interest in the Iris Marin exploration licence area offshore Gabon, which is operated by Sterling Energy. The Iris Marin licence area covers a shallow water exploration permit of approximately 99,600 acres (403 km^2).

The first exploration well in the Iris Marin PSC was drilled in August 2005. The well was drilled to a depth of 2,035 m, reaching a sub-salt Gamba sandstone target where it penetrated over 30 m of reservoir-quality sandstones that were water bearing. The well was plugged and abandoned as a dry hole. The Corporation drilled the Charlie prospect in 2008 but the well was unsuccessful. The Corporation has identified additional prospects in the Iris Marin licence area and is considering drilling another exploration well.

Gryphon Marin licence

Addax Petroleum operates and holds a 68.75 per cent interest in the Gryphon Marin exploration license. The license area covers a gross area of approximately 2,409,200 acres (9,750 km^2) and lies immediately west of the Iris Marin and Ibekelia license areas, and immediately north of the Corporation's Etame Marin license. The Corporation has full suite of seismic data on the license area including approximately 3,900 km^2 of modern 3D seismic and 2,100 km of 2D seismic. The Gryphon Marin license area is in an exploration period ending in November 2009 and carries a commitment to drill two wells. The Corporation has budgeted to drill the Ajomba and Ajomba South prospects in 2009 and a prospect inventory is being matured to determine future exploration plans for the license area

Ibekelia Technical Evaluation Agreement

Addax Petroleum holds a 40.0 per cent interest in an exploration licence area operated by Sterling Energy, under the Ibekelia technical evaluation agreement. The Ibekelia technical evaluation agreement covers a gross area of approximately 167,500 acres (678 km^2). In 2008, there was no activity on the Ibekelia technical evaluation agreement and the Corporation does not expect any activity in 2009. The operator is currently negotiating a new PSC to replace the technical evaluation agreement.

Budgeted Capital Expenditures

Capital expenditures for the Corporation's Gabon offshore properties are budgeted to be $60 million in 2009 under the existing capital expenditure budget of $1.6 billion. The budgeted capital expenditures are primarily intended to fund the development of the Etame and Ebouri fields and the drilling of three exploration wells; one in the Etame Marin licence area (Etame SE) and two in the Gryphon Marin licence area (Ajomba S and Ajomba N), as well as a possible seismic survey on Iris Marin.

Oil Sales Arrangements

In 2008, Addax Petroleum transported its crude oil entitlement from Maghena and Panthere NZE through the Coucal facilities to Cap Lopez under a transportation agreement with TOTAL Gabon and sold the crude oil to a subsidiary of TOTAL at Cap Lopez under a crude oil sales contract. The transportation agreement has a three year term that commenced in August 2006. The crude oil sales contract does not have a defined term but is in effect for the duration of the TOTAL Gabon transportation agreement. The Corporation's crude oil entitlement from Remboué is barged from the field and sold on a cargo by cargo basis to Addax Energy. Crude oil produced from Etame in 2008 was sold to Shell Western Supply & Trading Limited. Effective January 1, 2009, the Corporation is selling its crude oil from Etame to TOTAL SA pursuant to a one-year contract, expiring on December 31, 2009.

Addax Petroleum Crude Oil Premium/(Discount) to Brent Crude (Volume Weighted)(1)

	Year Ended December 31		
Sales and Marketing Volumes (MMbbl)	**2008**	**2007**	**2006**
Panthere NZE	0.6	0.9	0.2
Maghena	6.3	4.4	0.4
Awoun	0.6		
Remboué	0.2	0.2	0.1
Etame	2.4	2.3	0.6
Dated Brent Crude Price ($/bbl) (2)	96.99	72.52	60.12
Addax Petroleum Average Realized Prices ($/bbl)			
Panthere NZE	93.94	67.23	59.56
Maghena	94.58	69.66	58.14
Awoun	84.26		
Remboué	88.09	65.07	52.67
Etame	94.56	71.11	59.46
Premium/(Discount) to Brent Crude ($/bbl)			
Panthere NZE	(4.28)	(3.27)	(0.77)
Maghena	(4.00)	(5.50)	(2.16)
Awoun	(4.69)		
Remboué	(8.08)	(6.37)	(8.04)
Etame	(1.17)	(0.43)	(1.38)

Notes:

(1) Premium/(Discount) to Brent Crude are reported on a volume weighted basis for both the crude in question and Brent Crude, whereas Dated Brent Crude prices are reported as averages of monthly values for the period. Accordingly, the difference between the reported average realized petroleum prices and Dated Brent Crude prices may not correspond to the Premium/(Discount) to Brent Crude.

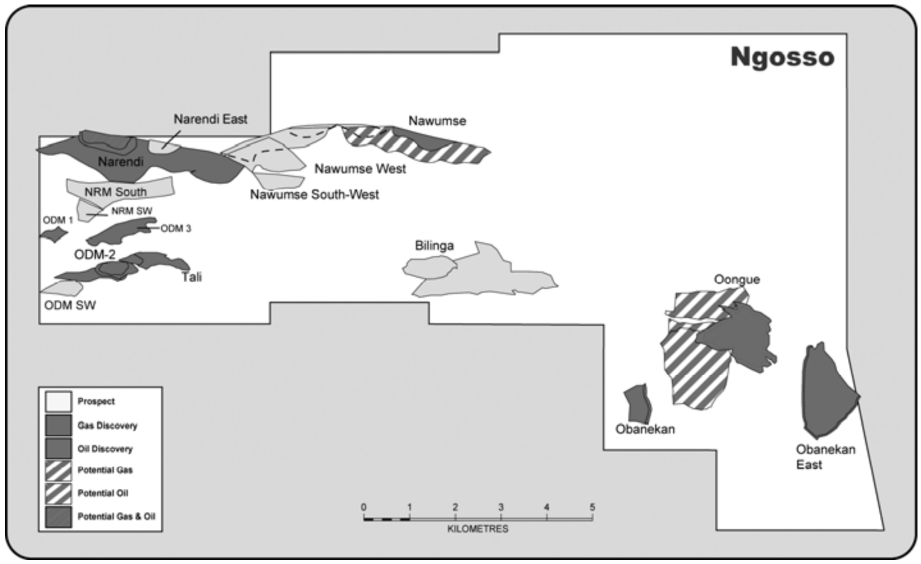
(2) Dated Brent Crude for 2006 is calculated from September 7, 2006 (the date of the Pan-Ocean Acquisition) to December 31, 2006. The full year figure is 65.11.

Cameroon

In Cameroon, Addax Petroleum has interests in one concession agreement and one PSC covering two shallow water offshore licence areas. Both licence areas in Cameroon are exploration properties. The Corporation had capital expenditures totalling $64 million in 2008 and has budgeted capital expenditures of $36 million in 2009 in Cameroon. This budgeted total capital expenditure amount is consistent with Addax Petroleum's philosophy of funding capital expenditures from internally generated cash flow and has been estimated using an average Brent Crude price of $60/bbl. Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, the Corporation will reduce capital expenditures to ensure that total capital expenditures continue to be funded by internally generated cash flow. An average Brent Crude price of $40/bbl would result in a reduction of spending to approximately $25 million.

Ngosso Licence

Overview



Addax Petroleum is the operator of the Ngosso licence area, with a 60 per cent interest. The Concession Agreement had an initial term of three years with a minimum work commitment for the acquisition of 200 km^2 of 3D seismic and the drilling of two exploration wells. This minimum work commitment was fulfilled in 2008. The Ngosso agreement is, subject to government approval, currently in a two year exploration phase with a one well commitment to be drilled by January 2011.

The Ngosso licence area is located in the hydrocarbon prone Rio Del Rey Basin, western offshore Cameroon and covers a gross area of approximately 117,100 acres (474 km^2). To the east, north and west, the Ngosso licence area has a common border with three concessions operated by TOTAL and with three open acreage areas. To the south, the Ngosso licence area is bordered by two concessions operated by TOTAL and by Shell and by open acreage. The Ngosso licence area lies adjacent to the shore in water depths of up to 8 m. It has similar operational and subsurface geological conditions to the Corporation's OML123, located approximately 20 km to the west.

Production and Reserves

There has been no production to date and no reserves have been booked for the Ngosso licence area.

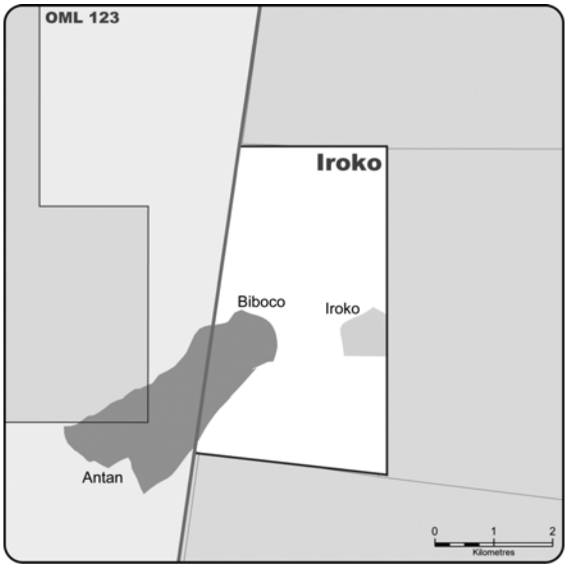
Unappraised Discoveries, Exploration and Prospective Oil Resources

Interpretation of 213 km^2 of 3D seismic acquisition (obtained in 2006 and 2007) and detailed evaluation of the seismic data identified eight exploration prospects. In 2008, Addax Petroleum drilled the Odiong and Tali prospects to satisfy its initial period exploration commitment. As part of the campaign, Addax Petroleum drilled a sidetrack to the initial Odiong well, which resulted in a small discovery. The amount of oil discovered, however, has been deemed to be uneconomic as a stand-alone development. The Corporation is continuing with the exploration of the Ngosso licence area and is considering alternatives to develop the Odiong sidetrack discovery together with earlier discoveries in the licence area. As at December 31, 2008 NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects in Ngosso to be 53.8 MMbbl (12.3 MMbbl risked).

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures for Ngosso are budgeted to be $30 million in 2009, primarily for the drilling of one exploration well (Oongue) and a 3D seismic survey.

Iroko Licence



Overview

Addax Petroleum acquired its interest in the Iroko licence area, offshore Cameroon, in 2008. The Corporation is the operator of the licence area and holds a 100 per cent interest. Société National des Hydrocarbures, the national oil company of Cameroon, holds a 30 per cent back in right in the case of any development. The Corporation's initial 3-year term carries a minimum work commitment of $17.5 million, including acquisition of 3D seismic data and drilling of one exploration well. Both of these commitments were satisfied in 2008 by the drilling of Iroko 1 and the acquisition of a high resolution 3D seismic survey. The Iroko licence area is located approximately 30 km offshore Cameroon in the Rio del Rey Basin, with a water depth of approximately 40 m. The licence area covers 3,900 acres (16 km^2) and is adjacent to the Shell-operated Mokoko-Abana field to the east, and OML123 to the west, offshore Nigeria.

Production and Reserves

There has been no production to date and no reserves booked for the Iroko licence area.

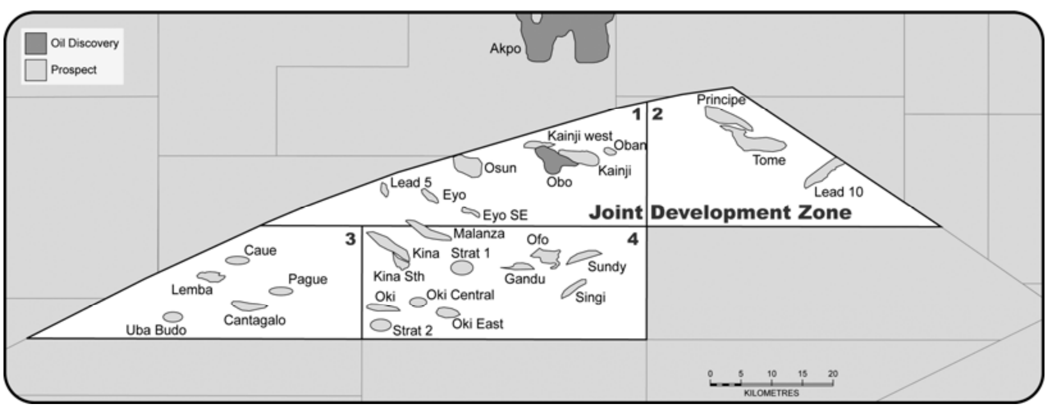
Unappraised Discoveries, Exploration and Prospective Oil Resources

In June 2008, Addax Petroleum drilled the Iroko prospect on the eastern part of the licence area, and the well encountered hydrocarbons. Addax Petroleum is currently evaluating the core, pressure and wireline data, and remapping using the 3D seismic data acquired in 2008.

Budgeted Capital Expenditures

The Corporation's capital expenditures for Iroko are budgeted to be $6 million in 2009 under the existing capital expenditure budget of $1.6 billion, primarily for additional studies.

Joint Development Zone



Overview

Addax Petroleum has various interests in four PSCs covering four deepwater licences in the Joint Development Zone. The JDZ lies in the Gulf of Guinea which is one of the most prolific hydrocarbon regions in the world. Intensive exploration efforts over the last 35 years in and around the Niger Delta Basin, in particular, have led to a succession of large discoveries, notably the Bonga, Agbami and Akpo discoveries in Nigeria and the Zafiro and Alba discoveries in Equatorial Guinea. The JDZ covers an area of approximately 8.5 million acres (34,500 km^2) with water depths ranging from approximately 1,500 m in the northern part of the JDZ to over 3,500 m at its south western sector.

Extensive regional 2D and 3D seismic data shot by a number of seismic contractors provide a high quality regional dataset that has provided insight into the region's geological character. Improved models of sand distribution have led to a better understanding of the prospectivity of the JDZ.

JDZ Properties

Between 2005 and 2007, Addax Petroleum built a prominent equity position in the JDZ that includes: (i) a 45.5% participating interest in Block 4; (ii) a 40% participating interest in Block 1; (iii) a 15% participating interest in Block 3; and (iv) a 14.33% participating interest in Block 2. Production Sharing Contacts for all four blocks were signed with the Joint Development Authority in March 2006. Addax Petroleum is the operator of Block 4 while Anadarko is the operator of Block 3, Sinopec is the operator on Block 2 and Chevron is the operator of Block 1.

A summary of the Corporation's holdings in this highly prospective region together with its minimum work obligations are provided in the following table:

Block	Net Acres	Addax Petroleum's Interest	Operator	Partner's Interest Carried by Addax Petroleum	Minimum Work Program to be funded by Addax Petroleum
	(acres)	*(%)*		*(%)*	*($ million)*
1	69,600	40.00	Chevron	0.00	0.0
2	24,500	14.33	Sinopec	7.33	6.1
3	24,700	15.00	Anadarko	10.00	7.5
4	96,300	45.50	Addax Petroleum	19.50	34.5
Totals	**214,100**				**48.1**

In June 2005, the Joint Development Authority announced that Block 4 would be awarded to ERHC Energy/Noble Energy JDZ (60 per cent interest) together with a consortium of other companies. The winning bid provided for a signing bonus of $90 million and a minimum work program of three exploration wells or a minimum expenditure of $53 million. In November 2005, Addax Petroleum entered into a participation agreement with ERHC Energy pursuant to which Addax Petroleum became entitled to a 33.3 per cent interest in Block 4 and replaced Noble Energy JDZ as operator for the consortium. The participation agreement with ERHC also required that Addax Petroleum pay $18 million to ERHC, commit to carry the costs associated with an ERHC interest of 17.7 per cent in Block 4 and assume its own portion of the minimum work program. In March 2006, the Corporation announced that it, together with its co-venture partners, had signed a PSC with the JDA. In April 2006, Addax Petroleum increased its interest in Block 4 to 38.3 per cent by acquiring the 5 per cent interest held by Overt Ventures Ltd. In July 2007, Addax Petroleum commenced arbitration proceedings against ERHC in respect an additional 9% assigned to the ERHC/Addax under the PSC, whereby Addax Petroleum claimed entitlement to an additional 7.2% participating interest, subject to carried costs associated with the balance, being 1.8%. The independent arbitral tribunal found in favour of Addax Petroleum, increasing its participating interest in Block 4 to 45.5%.

In March 2006, Addax Petroleum signed a PSC with the JDA and a participation agreement with ERHC for Block 3 of the JDZ where a subsidiary of Anadarko is the operator. Under the participation agreement with ERHC, Addax Petroleum, received a 15 per cent interest in Block 3 in return for the payment of $7.5 million and a commitment to carry the costs associated with an ERHC interest of 10 per cent in the block The PSC for Block 3 includes a minimum work program of one exploration well or a minimum expenditure of $30 million.

In March 2006, the Corporation also signed a PSC with the JDA and a participation agreement with ERHC for Block 2 of the JDZ where Sinopec is the operator. Under the participation agreement with ERHC, Addax Petroleum received a 14.33 per cent interest in Block 2 in return for the payment of $6.8 million and a commitment to carry the costs associated with an ERHC interest of 7.33 per cent in the block. The PSC for Block 2 includes a minimum work program of one exploration well or a minimum expenditure of $28 million.

In September 2007, Addax Petroleum consolidated its strategic entry into the Gulf of Guinea deep water exploration play with the acquisition of a 40 per cent interest in Block 1 of the Joint Development Zone. The acquisition included payment by Addax Petroleum to the vendor of $77.6 million as well as a two per cent share of Addax Petroleum's profit oil produced from Block 1. The operator of Block 1, Chevron, drilled the Obo-1 exploration well in 2006, which was reported as being oil and gas-bearing. The operator, Chevron, has notified the JDA of its intent to move into the second exploration phase for Block 1. Addax Petroleum's financial commitment for the second exploration phase is $10 million. The second exploration phase carries a minimum work commitment of the drilling of one well to a depth of 3,500 metres subsea as well as the acquisition and processing of seismic data and conducting geophysical and geological studies.

Production and Reserves

There has been no production to date and no reserves booked for the JDZ Blocks 1, 2, 3 or 4.

Exploration and Prospective Oil Resources

The JDZ is covered extensively by 2D and 3D seismic data. To date, the Corporation has identified a portfolio of at least 19 prospects on Blocks 1, 2, 3 & 4. Prospect identification and evaluation has been the result of in-depth analysis and interpretation of good quality seismic data. As at December 31, 2008 NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for identified prospects in the JDZ as follows:

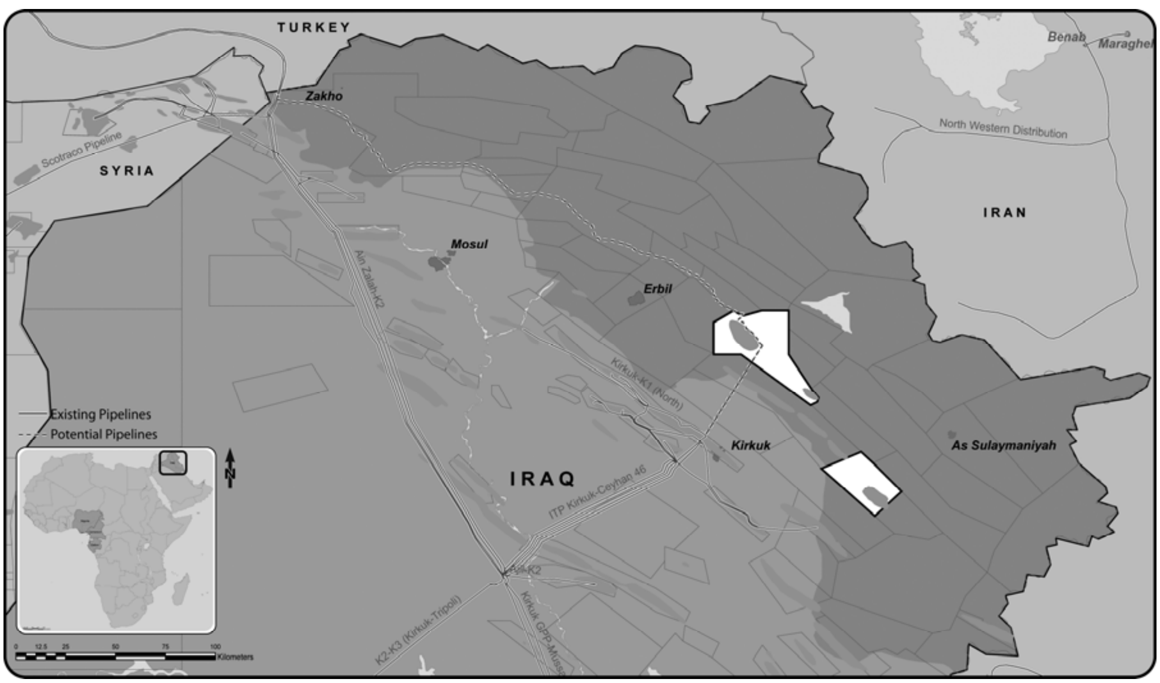
Block	**Best Estimate Prospective Oil Resources**	
	Unrisked *(MMbbl)*	**Risked** *(MMbbl)*
Block 1	172.9	66.0
Block 2	50.1	24.9
Block 3	41.0	13.1
Block 4	528.7	201.8

In March 2007, the Corporation entered into an agreement with Aban for the operation of the Aban Abraham deep water drillship to start drilling operations in 2008. The contract, which was entered into jointly by Addax Petroleum and Sinopec, requires Aban to drill up to ten wells in total comprising five firm well slots and five optional well slots. Well slots will be allocated under a separate agreement between Addax Petroleum and Sinopec. It is intended that firm well slots will be allocated to Addax Petroleum to satisfy its minimum work commitments on operated blocks in the deep water Gulf of Guinea. Payments under the contract are based on a day rate charging structure and a maximum day rate of $410,000, to be allocated appropriately to Addax Petroleum and its relevant co-ventures. The Aban Abraham is contracted to a third party prior to commencing operations for Addax Petroleum. The Corporation continues to monitor the likely time of arrival of the Aban Abraham, which may be delayed to late 2009 or into 2010. The Corporation is also actively seeking a rig of opportunity for earlier drilling.

Budgeted Capital Expenditures

Under the Corporation's existing capital expenditure budget of $1.6 billion, capital expenditures for the JDZ are budgeted to be $35 million in 2009, primarily to commence drilling activities in Block 4 (Kina Prospect) in the second half of the year.

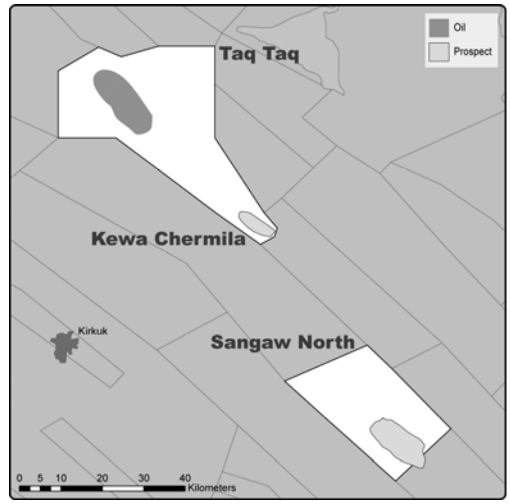
Kurdistan Region of Iraq



Addax Petroleum has interests in two PSCs in the Kurdistan Region of Iraq, covering two licence areas. The Taq Taq licence area is an exploration and early production property and the Sangaw North licence area is an exploration property. As at December 31, 2008, NSAI estimates the Corporation's gross proved reserves for the Kurdistan Region of Iraq to be 13.7 MMbbl, gross proved plus probable reserves to be 109.5 MMbbl and gross proved plus probable plus possible reserves to be 152.6 MMbbl. The Corporation had capital expenditures totalling $86 million in 2008 and has budgeted capital expenditures of $93 million in 2009 in the Kurdistan Region of Iraq. This budgeted total capital expenditure amount is consistent with Addax Petroleum's philosophy of funding capital expenditures from internally generated cash flow and has been estimated using an average Brent Crude price of $60/bbl. Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, the Corporation will reduce capital expenditures to ensure that total capital expenditures continue to be funded by internally generated cash flow. An average Brent Crude price of $40/bbl would result in a reduction of spending to approximately $75 million.

Taq Taq Licence Area

Overview



The Taq Taq licence area is in the Zagros basin where large, elongated anticlines dominate. The Taq Taq licence area is located 60 km northeast of the giant Kirkuk oil field and the adjacent city of Kirkuk, 85 km southeast of the city of Erbil and 120 km northwest of the city of Sulaimaniyah. The gross area of the Taq Taq Licence is approximately 235,100 acres (951 km^2).

Addax Petroleum's interests in the Taq Taq licence area are governed by the Amended Revised Taq Taq PSA, which was entered into in order to conform the Revised Taq Taq PSA to the model Production Sharing Agreement published by the KRG, and it gives the KRG the right to require that at a future date a government nominated entity is assigned a 20.0 per cent interest. Addax Petroleum holds a 45.0 per cent interest, which will be reduced to 36 per cent after the exercise of the KRG rights referred to above. Addax Petroleum and Genel Enerji have formed TTOPCO to conduct petroleum operations at the Taq Taq licence area.

Under the terms of a farm-in agreement with Genel Enerji, Addax Petroleum has funded 100 per cent of the initial work program to a maximum aggregate cost of $124 million and will pay to Genel Enerji an overriding royalty of 2.5 per cent of the production net of applicable royalties payable under the Revised Amended Taq Taq PSA, and after the deduction of a total of $50 million that was pre-funded by way of work program contribution and loan.

Production and Reserves

The following table summarizes the Corporation's reserves in the Taq Taq licence area after government back-in rights, which Addax Petroleum expects to be exercised. There has been intermittent small-scale commercial production to date, however, the Corporation's development plan anticipates building productive capacity over the next two years.

			Average Oil Production		**Gross Oil Reserves(1)**		
Licence	**Field**	**Number of Oil Producing Wells(2)**	**December 2008**	**12 Months Ended December 31, 2008**	**Proved**	**Proved plus Probable**	**Proved plus Probable plus Possible**
			(bbl/d)	*(bbl/d)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Taq Taq	Taq Taq	-	-	-	13.7	109.5	152.6
	Kewa Chermila	-	-	-	-	-	-
Total		**-**	**-**	**-**	**13.7**	**109.5**	**152.6**

Notes:

(1) As at December 31, 2008 as reported in the NSAI Reserve Report under "Forecast Prices and Costs Case".

(2) As at December 31, 2008.

Fields

Taq Taq

The Taq Taq field is an anticline of approximately 30 km by 10 km located 60 km northeast of the Kirkuk oil field. Kirkuk, discovered in 1927, is the second largest oil field in Iraq and is reportedly one of the largest oil fields in the world.

Since 2005, Addax Petroleum and Genel Enerji have been undertaking an appraisal and early development campaign at the Taq Taq field, which commenced with the acquisition of 170 km of 2D seismic over Taq Taq. Addax Petroleum and Genel Enerji then commenced drilling activities and completed the first jointly operated well (TT-04) in the Taq Taq licence area in late 2006. Between 2007 and the first half of 2008, the TT-05, TT-06, TT-07, TT-08 and TT-09 wells were flow tested at individual well aggregate rates of between 16,170 bbl/d and 37,560 bbl/d with oil gravity ranges of 44 to 50° API. In the majority of instances, three flow tests were conducted in sequentially well testing the three main cretaceous reservoir horizons, being the Shiranish, Kometan and Qamchuga formations. Interpretation of data acquired, including wireline static reservoir pressure data, indicates the presence of a significant and extensive fracture system and a single oil column in the Taq Taq field through the Shiranish, Kometan and Qamchuga formations in excess of 500 m In 2008 the TT-11 well was also drilled into the shallower Pila Spi formation, which had not been previously tested or fully evaluated, and for which no reserves had previously been booked. The Pila Spi formation was flow tested at 470 bbl/d with oil gravity of 23° API. The Corporation believes that the flow rate could be significantly enhanced with the introduction of an artificial lift system. .

In the first quarter of 2009 the TT-10 well will be tested and hooked up to the early production system (EPS) allowing for test oil to be monetised. The Taq Taq field is currently flowing oil through the EPS, which is being sold to local markets. The results of drilling and seismic programs and the dynamic data from the EPS are being integrated into a full field development plan. The first stage of this plan includes an early production system with a goal of increasing productive capacity to 60,000 bbl/d by the end of 2009. The first phase of the development plan is to be finalized and commissioned in 2009. In the event that development proceeds to full commercial development, the Taq Taq licence area would require the construction of a pipeline for export, and the Corporation is currently carrying out the FEED and ESIA on export pipeline options. Any export pipeline would be subject to government approvals.

Kewa Chirmila

The Kewa Chirmila prospect covers an area of approximately 4,000 acres (15 km^2) within the Taq Taq licence area. The prospect is a crestal surface expression similar to but roughly one-third of the size of the Taq Taq field. In 2007, a 218 km 2D seismic survey was acquired over Kewa Chirmila and the Taq Taq area, excluding the Taq Taq field. Addax Petroleum and Genel Enerji are currently drilling the first exploration well at Kewa Chermila.

Budgeted Capital Expenditures

Capital expenditures for the Taq Taq licence area are budgeted to be $66 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion. The budgeted capital expenditures is intended to fund the remainder of the first development phase of the Taq Taq field, including exploration and appraisal drilling and facilities installation.

Sangaw North Licence Area

Overview

The Sangaw North licence area covers an area of approximately 121,600 acres (492 km^2) and is located 80 km south-east of the Taq Taq field. It contains a large surface anticline and a number of surface oil seeps. The Corporation holds a 26.67 per cent working interest in the Sangaw North PSC. The KRG has the right to require that at a future date a government-nominated entity is assigned 25 per cent which, if exercised, will reduce Addax Petroleum's interest to 20 per cent.

Production and Reserves

There has been no production to date and no reserves have been booked for Sangaw North.

Unappraised Discoveries, Exploration and Prospective Oil Resources

The operator, Sterling Energy, has acquired 300 km of 2D seismic data which is currently being processed. Preliminary technical evaluation is expected to be completed, and the commitment well drilled in 2009. As at December 31, 2008, NSAI estimates the Corporation's gross working interest best estimate unrisked prospective oil resources for Sangaw North to be 125.9 MMbbl (14.4 MMbbl risked).

Budgeted Capital Expenditures

Capital expenditures for the Sangaw North licence areas are budgeted to be $27 million in 2009 under the Corporation's existing capital expenditure budget of $1.6 billion. The budgeted capital expenditures are intended to fund seismic processing as well as geologic, geophyisical and engineering studies with a view to a first exploration well in 2009.

2009 Total Budgeted Capital Expenditures

The following table summarizes the Corporation's budgeted capital expenditures for 2009.

Licence/Category	Development Drilling ($million)	Development Facilities & Other ($million)	Development Total ($million)	Exploration, Appraisal & Other ($million)	Total ($million)
Nigeria					
OML123/124	327	142	469	23	492
OML126/137	222	160	382	112	494
Okwok	–	4	4	–	4
Other Nigeria	–	–	–	17	17
subtotal	**549**	**306**	**855**	**152**	**1,007**
Gabon					
Onshore Gabon	172	151	323	42	365
Offshore Gabon	13	3	16	44	60
subtotal	**185**	**154**	**339**	**86**	**425**
Cameroon	**–**	**–**	**–**	**36**	**36**
JDZ Blocks 1,2, 3 & 4	**–**	**–**	**–**	**35**	**35**
Kurdistan Region of Iraq					
Taq Taq	–	57	57	9	66
Sangaw North	–	–	–	27	27
subtotal	**–**	**57**	**57**	**36**	**93**
Other					
Corporate	–	4	4	–	4
Total	**734**	**521**	**1,255**	**345**	**1,600**

Columns may not add due to rounding

This budget is consistent with Addax Petroleum's philosophy of funding capital expenditures from internally generated cash flow and has been determined using an average Brent Crude price of $60/bbl.

Should the prevailing Brent Crude price continue to be below $60/bbl for the balance of 2009, Addax Petroleum intends to reduce its capital expenditures such that total capital expenditures continue to be funded by internally generated cash flow. An average Brent Crude price of $40/bbl would result in a reduction of capital expenditures to $1 billion and the associated reduced drilling and facilities expenditures would result in the Corporation's total production for 2009 averaging between 132,000 bbl/d and 137,000 bbl/d. In Nigeria, this would result in reduced capital expenditures to approximately $450 million and an associated reduction in total average production in Nigeria to between 100,000 bbl/d and 104,000 bbl/d. In Gabon, this would result in a reduction of spending to approximately $400 million, with no change to production guidance for 2009. In Cameroon, this would result in a reduction of spending to approximately $25 million. In the Kurdistan Region of Iraq, this would result in a reduction of spending to approximately $75 million. In the JDZ, this would result in no change to capital expenditures.

Fiscal Terms

Nigeria Onshore and Shallow Water PSCs (OML123/124, OML126/137)

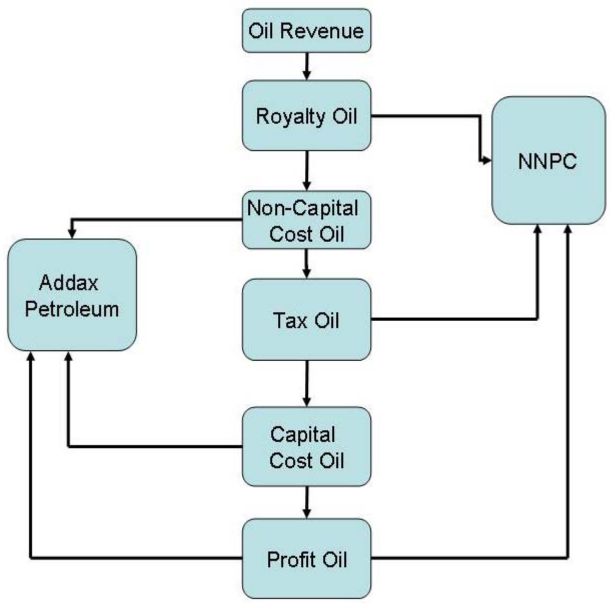
In May 1998, the Corporation and NNPC entered into a Production Sharing Contract covering both of OML123 and OML124 and a Production Sharing Contract covering both of OML126 and OML137. These contracts are supplemented by the provisions of the *Petroleum Act*, and the regulations thereunder, and the *PPT Act*. The fiscal terms of the Production Sharing Contracts were modified by the terms of the letter entitled "Fiscal Regimes for Onshore and Shallow Offshore PSC", issued on November 21, 2001 by the Office of the Presidential Adviser on Petroleum and Energy with retroactive effect to January 1, 2000. Both of these Nigerian Production Sharing Contracts have a term of 20 years expiring in May 2018.

Under each of its Nigerian Production Sharing Contracts, Addax Petroleum bears the development and exploration risk for the properties concerned and funds all of the necessary capital expenditures. In return, the Corporation is entitled to sell sufficient oil to recover its capital expenditures and operating costs and to have a designated share of oil production remaining after the payment of royalties and taxes. Each of these two Nigerian Production Sharing Contracts impose minimum work obligations and Addax Petroleum has fulfilled the minimum work obligations. Taxation of each Production Sharing Contract is calculated independently of Addax Petroleum's other Production Sharing Contracts and as a result, capital expenditure recovery is available to the extent of the profitability of the particular Production Sharing Contract on which the capital expenditures were incurred. Oil produced under the Nigerian Production Sharing Contracts is notionally allocated to one of four categories in the following order.

1. Royalty Oil
2. Cost Oil
3. Tax Oil
4. Profit Oil

Royalty Oil and Tax Oil are allocated to NNPC while Cost Oil is allocated to Addax Petroleum. Profit Oil is shared between NNPC and Addax Petroleum. The Production Sharing Contracts provide for each party to lift and sell its oil entitlement, though NNPC can request that Addax Petroleum lift and sell on its behalf.

Allocation of Oil Production under the Nigerian PSCs



The proportion of production that is designated for each of Royalty Oil, Cost Oil, Tax Oil and Profit Oil in a particular time period is influenced by oil prices, production levels, operating costs, capital expenditures and costs and allowances carried forward from previous periods in accordance with the terms of the Production Sharing Contracts. The fiscal terms have the effect of reducing the percentage of revenues paid as Tax Oil during periods of lower oil prices and increasing such percentage during periods of higher oil prices.

Royalty Oil is calculated on a field by field basis and varies with the field's production rate and water depth. For each level of the field's production a specific royalty rate is applied on an incremental sliding scale basis.

	Royalty Oil Rates Field Range of Production (bbl/d)					
Water Depth	**<2,000**	**2,000-5,000**	**5,000-10,000**	**10,000-15,000**	**15,000-25,000**	**>25,000**
	(%)	(%)	(%)	(%)	(%)	(%)
Onshore	5.0	7.5	15.0	20.0	20.0	20.0
<100	2.5	2.5	7.5	12.5	18.5	18.5
100-200	1.5	1.5	3.0	5.0	10.0	16.7

Royalty Oil is accounted for on a monthly basis.

Other levies include the payments to the NDDC levy, calculated as three per cent of budgeted operating costs and capital expenditures, and education tax, calculated as two per cent of assessable profit for Tax Oil (see below). These levies are paid in cash to the relevant Nigerian authority.

Cost Oil is allocated to Addax Petroleum in such an amount as to enable the recovery of all recoverable costs. The accounting procedure attached to the Production Sharing Contracts divides costs into two categories: non-capital costs and capital costs. Non-capital costs are expensed and include operating costs, a head office overhead allowance, interest on loans approved by NNPC, gas flaring charges, licence fees, customs duties, intangible drilling costs, geological and geophysical surveys, exploration and appraisal drilling and funded abandonment provisions. Historically, under the Production Sharing Contracts, Addax Petroleum has recovered approximately 80 per cent of all drilling and seismic expenditures in the fiscal period in which they were incurred. Capital costs are depreciated over a five year period at 20 per cent straight-line starting in the year of first production, except for the fifth year which is depreciated at 19 per cent. All costs prior to the first lifting on a Production Sharing Contract are capitalized.

Maximum Cost Oil available is calculated as total production less Royalty Oil. Cost Oil is calculated on a monthly basis and any excess costs are carried forward to subsequent months or years. As at December 31, 2008, the Cost Oil carry-forward balances, including capital depreciation carried forward to future years, were as set out in the following table.

	Cost Oil Carry-Forward Balances			
	2009	**2010**	**2011**	**2012**
		($ million)		
OML123/124 PSC	141.4	130.7	101.0	62.2
OML126/137 PSC	102.6	36.1	15.4	12.1

Tax Oil is calculated after deducting Royalty Oil and Cost Oil. The calculation of Tax Oil is specified by the *PPT Act* and the applicable rate for the Corporation's onshore and shallow water Production Sharing Contracts is 60 per cent of taxable profit. In the event that after the deduction of capital allowances and capital investment allowances the tax to be paid is zero, a 15 per cent tax charge is made on the taxable amount before the deduction of certain capital allowances and capital investment allowances. The accounting period for Tax Oil is a calendar year. Taxable profit is equal to revenue less Royalty Oil, NDDC levy, education tax, non-capital costs, capital depreciation and an investment tax allowance. The investment tax allowance is calculated as an uplift of 40 per cent of offshore capital costs and 25 per cent of onshore capital costs.

The Corporation's onshore and shallow water Production Sharing Contracts also contain a tax inversion penalty which is designed to encourage oil companies to contain operating costs. The tax inversion penalty for production rates less than 50 Mbbl/d is calculated at 25 per cent of operating costs in excess of $7.50/bbl. For production rates more than 50 Mbbl/d, the tax inversion penalty is calculated at 25 per cent of operating costs above $5.00/bbl.

Profit Oil is the oil remaining after deducting Royalty Oil, Cost Oil and Tax Oil. Profit Oil is shared between NNPC and Addax Petroleum on a sliding scale based on monthly production from the respective onshore and shallow water Production Sharing Contracts. The varying allocations between NNPC and Addax Petroleum are applied on an incremental sliding scale basis.

Profit Oil Sliding Scale

	OML123 / OML124		**OML126 / OML137**	
Monthly Average Production	**NNPC Share**	**Addax Petroleum Share**	**NNPC Share**	**Addax Petroleum Share**
(bbl/d)	(%)	(%)	(%)	(%)
≤ 40,000	30	70	20	80
> 40,000 and ≤ 75,000	45	55	35	65
> 75,000 and ≤ 100,000	55	45	45	55
> 100,000	60	40	50	50

The following example illustrates how oil is allocated between the four categories under the Corporation's Nigerian Production Sharing Contracts. The example compares two scenarios each with annual revenues of $200, annual operating costs of $20 and no loss or allowances carried forward. For the purposes of the illustration, Royalty Oil is assumed to be levied at five per cent, NDDC levy at three per cent, education tax at two per cent, Tax Oil at 60 per cent and NNPC's share of Profit Oil at 30 per cent. The impact of capital expenditures of $100 in Year 1 has an after tax and Profit Oil cash flow effect of only a $70 reduction in Year 1 and an increase of almost $15 in the following four years such that the aggregate incremental cash flow reduction over the five year period is approximately $10, assuming no revenue benefit arises from the investment. The following table has been included as an example only and actual results may vary materially.

		Without Capital Expenditure		**With Capital Expenditure**	
		Year 1	**Years 2 to 5**	**Year 1**	**Years 2 to 5**
Tax Oil Computation:					
	Total PSC Revenue	200.0	200.0	200.0	200.0
less	non-capital costs	20.0	20.0	20.0	20.0
less	Royalty Oil	10.0	10.0	10.0	10.0
less	NDDC levy	0.6	0.6	3.6	0.6
yields	**Assessable Profit**	**169.4**	**169.4**	**166.4**	**169.4**

		Without Capital Expenditure		With Capital Expenditure	
		Year 1	**Years 2 to 5**	**Year 1**	**Years 2 to 5**
less	education tax	3.4	3.4	3.3	3.4
yields	**Adjusted Assessable Profit / (Loss)**	**166.0**	**166.0**	**163.1**	**166.0**
less	capital depreciation	0.0	0.0	20.0	20.0
less	investment tax allowance	0.0	0.0	40.0	0.0
yields	Taxable profit	166.0	166.0	103.1	146.0
times	Tax Oil rate	60%	60%	60%	60%
yields	**Tax Oil**	**99.6**	**99.6**	**61.8**	**87.6**
Profit Oil Computation:					
	Total PSC Revenue	200.0	200.0	200.0	200.0
less	Royalty Oil	10.0	10.0	10.0	10.0
less	operating expenditure	20.0	20.0	20.0	20.0
less	NDDC	0.6	0.6	3.6	0.6
less	education tax	3.4	3.4	3.3	3.4
less	Tax Oil	99.6	99.6	61.8	87.6
less	capital depreciation	0.0	0.0	20.0	20.0
yields	**Profit Oil**	**66.4**	**66.4**	**81.3**	**58.4**
yields	**Profit Oil – Contractor Share**	**46.5**	**46.5**	**56.9**	**40.9**
yields	**Profit Oil – NNPC Share**	**19.9**	**19.9**	**24.4**	**17.5**
Oil Allocation of Total PSC Revenue:					
	Cost Oil	20.0	20.0	40.0	40.0
	Profit Oil — Contractor Share	46.5	46.5	56.9	40.9
	Contractor Total	**66.5**	**66.5**	**96.9**	**80.9**
	Royalty Oil	10.0	10.0	10.0	10.0
	Tax Oil	99.6	99.6	61.8	87.6
	Profit Oil — NNPC's share	19.9	19.9	24.4	17.5
	NDDC levy and education tax	4.0	4.0	6.9	4.0
	Government Total	**133.5**	**133.5**	**103.1**	**119.1**
Contractor Cash Flow Computation:					
	Contractor Total Oil Allocation	66.5	66.5	96.9	80.9
less	operating expenditure	20.0	20.0	20.0	20.0
less	capital expenditure	0.0	0.0	100.0	0.0
yields	**Contractor Cash Flow**	**46.5**	**46.5**	**(23.1)**	**60.9**

Between the commencement of its activities under the onshore and shallow water Production Sharing Contracts and the end of 2003, Addax Petroleum lifted and sold all of NNPC's oil on their behalf but since the beginning of 2004, NNPC has lifted its entitlement. Under the Corporation's Nigerian Production Sharing Contracts, oil is valued based upon the appropriate "Realizable Price". The "Realizable Price" is equivalent to the Official Selling Price which is a price issued on a monthly basis by NNPC and is calculated by NNPC to equate to the prevailing international price in arm's length transactions, taking into account the properties of each crude blend.

Deepwater Production Sharing Contract (OPL291)

Addax Petroleum's interest in OPL291 is governed by a Production Sharing Contract with the NNPC which was entered into in October 2006. The OPL291 PSC has a term of 30 years expiring in 2036 and imposes minimum work obligations and financial commitments which the Corporation is required to undertake and fund. The Corporation is required to complete the first phase of its work commitments within five years of signing.

The PSC for OPL291 follows the same structure as the PSCs governing OML123/124 and OML126/137 in that oil produced under the OPL291 PSC is notionally allocated to the following four categories: Royalty Oil, Cost Oil, Tax Oil and Profit Oil. The calculation of Royalty Oil is based on a rate of 8.0 per cent of total production. In addition, the Corporation is subject to other levies on OPL291, including the payments to the NDDC levy, calculated as three per cent of budgeted operating costs and capital expenditures, and education tax, calculated as two per cent of assessable profit for Tax Oil.

Cost Oil is allocated to the Corporation in such an amount as to enable the recovery of all recoverable costs. The accounting procedure attached to the Production Sharing Contracts divides costs into two categories: non-capital costs and capital costs. Non-capital costs are expensed and include operating costs, a head office overhead allowance, interest on loans approved by NNPC, gas flaring charges, licence fees, customs duties, intangible drilling costs, geological and geophysical surveys, exploration and appraisal drilling and funded abandonment provisions. Capital costs are depreciated over a ten year period at 10 per cent straight-line starting in the year of first production. All costs prior to the first lifting on a Production Sharing Contract are capitalized. The capital and operating costs incurred in a particular year and any previous amounts carried forward from previous years can be fully recovered each year up to a maximum level of 80 per cent of total production.

Tax Oil is calculated at a rate of 50 per cent of taxable profit. Taxable profit is equal to revenue less Royalty Oil less an investment tax allowance. The investment tax allowance is calculated as an uplift of 50 per cent of NDDC levy, education tax, non-capital costs, capital depreciation and capital costs.

Profit Oil is the oil remaining after the deduction of Royalty Oil, Cost Oil and Tax Oil. Profit Oil is shared between Addax Petroleum and NNPC pursuant to the following sliding scale:

R Factor	Addax Petroleum's Profit Oil Share
R < 1.2	70%
1.2 < R < 2.5	25% + (((2.5-R) / (2.5 - 1.2)) x (70% - 25%))
R > 2.5	25%

Where, for each block:

$$R = \frac{\text{Cumulative Cost Oil + Cumulative Corporation Share of Profit Oil}}{\text{Cumulative Capital and Non-Capital Costs}}$$

Marginal Fields Fiscal Regime (Okwok)

The Okwok property is subject to the provisions of the *Petroleum Act* and the regulations thereunder, and the *PPT Act*. The fiscal terms of Nigerian Marginal Fields are the subject of legislative proposals to encourage development. The Marginal Fields comprise a number of ring-fenced fields located on concessions already awarded to joint ventures between international oil companies and NNPC and which have reserves booked to the Nigerian Department of Petroleum Resources and have remained un-produced for a period of over 10 years. The Nigerian Marginal Fields are assigned to indigenous Nigerian oil companies who conclude farm-in agreements with the joint ventures and can, in turn, farm-out to other operators.

The Marginal Fields are subject to Royalty Oil and Tax Oil payable to government agencies. The calculation of Royalty Oil and Tax Oil is discussed below.

Royalty Oil is calculated on a field by field basis and varies with the field's production rate and the depth of water. For each level of the field's production a specific royalty rate is applied on an incremental sliding scale basis.

Anticipated Royalty Oil Rates for the Okwok Property Field Range of Production (Mbbl/d)

< 2	2-5	5-10	10-15	15-25	25
(%)	(%)	(%)	(%)	(%)	(%)
2.5	2.5	7.5	12.5	18.5	18.5

Royalty Oil is accounted for on a monthly basis and paid within 60 days of the end of the chargeable period.

Other levies include the payments to the NDDC levy, calculated as three per cent of budgeted operating costs and capital expenditures, and education tax, calculated as two per cent of assessable profit for Tax Oil (see below).

Tax Oil is calculated after deducting Royalty Oil and non-capital costs and capital costs. Non-capital costs are expensed and include operating costs, a head office overhead allowance, interest on loans approved by NNPC, gas flaring charges, licence fees, customs duties, intangible drilling costs, geological and geophysical surveys, exploration and appraisal drilling and funded abandonment provisions. Capital costs are depreciated over a five year period at 20 per cent on straight-line basis starting in the first year of production. The calculation of Tax Oil is specified by the *PPT Act* and the applicable rate for the Nigerian Marginal Fields is anticipated to be 55 per cent of taxable profit. The accounting period for Tax Oil is a calendar year. Taxable profit is equal to revenue less Royalty Oil, NDDC levy, education tax, non-capital costs, capital depreciation and an investment tax allowance. The investment tax allowance is calculated as an uplift of 10 per cent of capital expenditures for offshore fields where the water depth is less than 100 m.

In addition to the fiscal terms described above, Addax Petroleum's interest in the Okwok property is subject to the terms and conditions of the Oriental Joint Venture Agreement.

Gabon Production Sharing Contracts

Nine of Addax Petroleum's ten licences are pursuant to Production Sharing Contracts with the Government of Gabon and one, Ibekelia, is pursuant to a technical evaluation agreement.

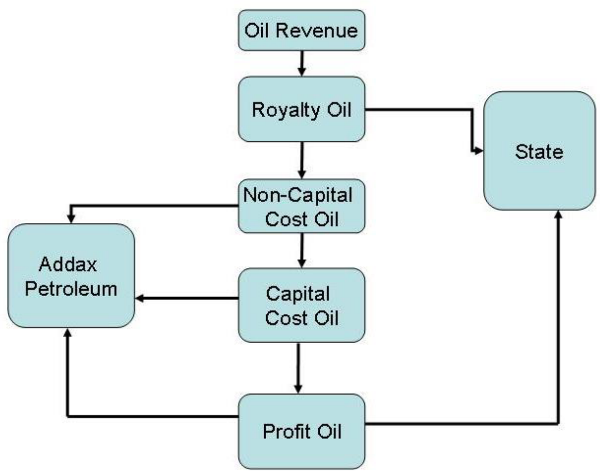
Under each of its Gabon Production Sharing Contracts, Addax Petroleum bears the development and exploration risk for the properties concerned and funds all of the necessary capital expenditures. In return, the Corporation is entitled to sell sufficient oil to recover its capital expenditures and operating costs and to have a designated share of oil production remaining after the payment of royalties. Taxation of each Gabon Production Sharing Contract is calculated independently of Addax Petroleum's other Gabon Production Sharing Contracts and as a result, capital expenditure recovery is available to the extent of the profitability of the particular Gabon Production Sharing Contract on which the capital expenditures were incurred.

Oil produced under the Gabon Production Sharing Contracts is notionally allocated to one of three categories in the following order.

1. Royalty Oil
2. Cost Oil
3. Profit Oil

Royalty Oil is allocated to the Government of Gabon while Cost Oil is allocated to Addax Petroleum. Profit Oil is shared between the Government of Gabon and Addax Petroleum.

Allocation of Oil Production under the Gabon PSCs



The proportion of production that is designated for each of Royalty Oil, Cost Oil and Profit Oil in a particular time period is influenced by oil prices, production levels, operating costs, capital expenditures and costs and allowances carried forward from previous periods in accordance with the terms of the Gabon Production Sharing Contracts.

Royalty Oil is calculated on a field by field basis and varies with the field's production rate and the depth of water. For each level of the field's production a specific royalty rate is applied on an incremental sliding scale basis.

Cost Oil is allocated to Addax Petroleum in such an amount as to enable the recovery of all recoverable costs. Capital and operating costs incurred in a particular year and any previous amounts carried forward from previous years can be fully recovered each year up to a cost recovery limit defined as a percentage of total production. The cost recovery limit is set according to the terms in each Gabon Production Sharing Contract. Maximum Cost Oil available is calculated as total production less Royalty Oil. Cost Oil is calculated on a monthly basis and any excess costs are carried forward to subsequent months or years. As at December 31, 2008, the Cost Oil carry-forward balances were as set out in the following table.

	Carry-Forward Cost Oil Balances
	($ million)
Maghena	40.9
Panthere NZE	112.7
Remboué	8.9
Awoun	110.3
Etame	15.6

	Carry-Forward Cost Oil Balances
	($ million)
Iris	15.1
Epaemeno	27.5
Gryphon Marin	25.8
Kiarsseny	11.5

Profit Oil is the oil remaining after deducting Royalty Oil and Cost Oil. Profit Oil is shared between the Government of Gabon and Addax Petroleum on a sliding scale based on monthly production from the respective Gabon Production Sharing Contracts. The varying allocations between the Government of Gabon and Addax Petroleum are applied on an incremental sliding scale basis. The principal terms of Addax Petroleum's Gabon Production Sharing Contracts are summarized as follows:

Permit	Maghena	Panthere NZE	Remboué	Awoun[(1)]	Etame Marin[(2)]	Iris Marin[(3)]	Epaemeno[(2)]	Gryphon Marin	Kiarsseny
Status	Production (Tsiengui)	Production (Obangue, Autour)	Production (Remboué)	Production (Tsengui West)	Production (Etame, Avouma)	Exploration	Exploration	Exploration	Exploration
Corporation's interest	92.50%	92.50%	92.00%	40.00%	31.36%	51.33%[(6)]	50.00%[(6)]	68.75%[(6)]	42.50%[(6)]
Third Party carry[(4)]	7.5%	7.5%	8.0%	0.0%	7.5%	7.5%	7.5%	10.0%	5.0%
Royalty									
bbl/d									
0-10,000	4.5 to 7%	3 to 5%	3 to 5%	5%	3 to 9%	6%	10%	4%	2%
10,001-20,000	11%	5%	5%	8%	12 to 15%	8%	10%	4%	3 to 5%
>20,000	11%	5%	5%	10%	15 to 17.5%	10% to 12%	10 to 12%	6% to 15%	7.5 to 10%
Cost recovery limit	75%	80%	80%	65%	70%	80%	70%	70%	75%
Addax Petroleum Profit Share									
bbl/d									
0-5,000	47.5%	50%	50 to 40%	50%	50%	50%	65%	50%	50%
5,000-10,000	40%	42.5%	35%	50%	50%	45%	65%	50%	50%
10,001-20,000	35%	30 to 20%	35%	42.5%	45%	35 to 30%	65 to 60%	50%	50 to 48%
>20,001	30 to 20%	20%	35%	40 to 30%	45 to 40%	25 to 20%	60 to 30%	45 to 10%	48 to 30%
Term[(5)]	10+5+5 years	10+5+5 years	10+5+5 years	10+5+5 years	10+5+5 years	10+5+5 years	10+3+3 years	10+5+5 years	4+3+3 years
Effective Date	June 26, 1997	December 6, 1996	February 17, 2001	December 27, 1999	July 7, 1997	November 2, 1999	November 17, 2004	December 13, 1995	March 11, 2003

Notes:

(1) The Awoun Production Sharing Contract provides that, once commercial production has commenced, the contractor shall contribute annually to a hydrocarbon support fund for petroleum research in Gabon calculated on the basis of $250,000 per annum during the exploration phase and $0.05 per barrel of total oil produced during the production phase.

(2) The Etame and Epaemeno Production Sharing Contracts provide that the contractor shall contribute annually to a hydrocarbon support fund for petroleum research in Gabon calculated on the basis of $60,000 per annum during the exploration phase and $75,000 per annum and $0.05 per barrel of total oil production produced during the production phase.

(3) The Iris Production Sharing Contract provides that, once commercial production has commenced, the contractor shall contribute annually to a hydrocarbon support fund for petroleum research in Gabon calculated on the basis of the total oil production of $0.05 per barrel produced.

(4) The Government of Gabon sold its carried interest to Sinopec for the Awoun PSC. Under the Production Sharing Contracts, should the government wish to acquire an additional interest it shall inform the contractor in writing and the parties shall mutually agree to such acquisition. Under certain of the Production Sharing Contracts, Gabonese investors have the option of acquiring a 2.5% participating interest within a certain period of time following commercial production failing which the government shall retain the right to acquire such interest.

(5) As a general rule, production terms of Production Sharing Contracts are initially for ten years and may be renewed for two subsequent five-year terms.

(6) Before government back-in.

All of Addax Petroleum's Gabon Production Sharing Contracts grant the Government of Gabon the right to terminate the Production Sharing Contracts by operation of law by serving a 15-day notice upon certain violations of the Production Sharing Contract, including the failure by the contractors to provide the Government of Gabon, within the prescribed time, the information specified in the Production Sharing Contract, the failure by the contractors to make all monetary payments under the Production Sharing Contract when due and the failure by the contractors to comply, in a material manner, with the terms of the Production Sharing Contract or any licence or lease issued thereunder. The Production Sharing Contracts further provide that, according to petroleum legislation in Gabon and within five years from the effective production date, an agreement shall be entered into with the State in order to establish an abandonment cost reserve fund.

Joint Development Zone

Addax Petroleum's interests in the JDZ are governed by Production Sharing Contracts with the Joint Development Authority which were all entered into in March 2006. Each of the Corporation's JDZ PSCs has a term of 28 years expiring in 2035. Each of the JDZ PSCs imposes minimum work obligations and financial commitments which the Corporation is required to undertake and fund. The Corporation is required to complete the first phase of work commitments within four years of signing.

Under each of its JDZ PSCs, Addax Petroleum bears the development and exploration risk for the properties concerned and funds all of the necessary capital expenditures. In return, the Corporation is entitled to sell sufficient oil to recover its capital expenditures and operating costs and to have a designated share of oil production remaining after the payment of royalties and taxes. Taxation of each JDZ PSC is calculated independently of Addax Petroleum's other JDZ PSC and as a result, capital expenditure recovery is available to the extent of the profitability of the particular JDZ PSCs on which the capital expenditures were incurred.

Oil produced under the JDZ PSCs is notionally allocated to the same four categories as the Nigerian PSCs, namely, Royalty Oil, Cost Oil, Tax Oil and Profit Oil. The calculation of Royalty Oil varies with the block's production rate on a sliding scale between 0.0 per cent for production below 20,000 bbl/d and 5.0 per cent for production in excess of 70,000 bbl/d. Cost Oil is allocated to the Corporation in such an amount as to enable the recovery of all recoverable costs. The capital and operating costs incurred in a particular year and any previous amounts carried forward from previous years can be fully recovered each year up to a maximum level of 80 per cent of the sum of total production less Royalty Oil. Tax Oil is calculated at a rate of 50 per cent of taxable profit. Taxable profit is equal to revenue less Royalty Oil less Cost Oil less an investment tax allowance. The investment tax allowance is calculated as a 50 per cent uplift of eligible capital costs. Profit Oil is the oil remaining after the deduction of Royalty Oil, Cost Oil and Tax Oil. Profit Oil is shared between Addax Petroleum and the JDA pursuant to the following sliding scale for each block:

R Factor	Addax Petroleum's Profit Oil Share
R < 1.2	80%
1.2 < R < 2.5	25% + (((2.5-R) / (2.5 - 1.2)) x (80% - 25%))
R > 2.5	25%

Where, for each block:

$$R = \frac{\text{Cumulative Cost Oil + Cumulative Corporation Share of Profit Oil}}{\text{Cumulative Capital and Non-Capital Costs}}$$

Kurdistan Region of Iraq

Taq Taq

Addax Petroleum's interests in the Taq Taq licence area are governed by the Amended Revised Taq Taq PSA under which Addax Petroleum and Genel Enerji are the contractors. The Amended Revised Taq Taq PSA has, with respect to the Taq Taq field and the Kewa Chermila Area, a term of 20 years from February 26, 2008, with an automatic right to a five-year extension and imposes minimum work obligations and financial commitments which the Corporation is required to undertake and fund.

The purpose of the amendments was to bring the PSA into conformity with the Oil and Gas Law of the Kurdistan Region of Iraq (the "Oil and Gas Law") and Model PSC, including the royalty, cost recovery and profit share components. The review and renegotiations were conducted between the KRG, Genel Enerji and Addax Petroleum in accordance with Article 54 of the Oil and Gas Law, which required review of the Taq Taq PSC by the Regional Council for Oil and Gas Affairs of the Kurdistan Region of Iraq, taking into consideration the prevailing conditions when the Taq Taq PSA was originally entered into.

Under the Amended Revised Taq Taq PSA, the contractors bear the development and exploration risk for the properties concerned and fund all of the necessary capital expenditures. In return, the contractors are entitled to sell sufficient oil to recover their capital expenditures and operating costs and to have a designated share of oil production remaining after the payment of royalties. Taxation of the Taq Taq field area and the exploration area of the Taq Taq licence area are unified under the Amended Revised Taq Taq PSA.

Oil produced under the Amended Revised Taq Taq PSA is notionally allocated to the same three categories as the Gabon PSCs, namely, Royalty Oil, Cost Oil and Profit Oil. However, prior to the PSA terms taking effect, there is an interim period during which all crude oil sales are to be allocated 60 per cent to the contractor and 40 per cent to the KRG, up to a maximum of $400 million in cumulative revenues.

Royalty Oil is calculated quarterly and is charged at a flat rate of 10 per cent on export crude oil and export non-associated natural gas. Associated natural gas is exempt from royalties. From first production in the contract area, Cost Oil is fully recovered up to 40 per cent of available crude oil and available associated natural gas within any calendar year, less Royalty Oil. Profit Oil is the oil remaining after the deduction of Royalty Oil and Cost Oil. Profit Oil is shared between Addax Petroleum and the KRG pursuant to the following sliding scale for each block for crude oil:

R Factor	Addax Petroleum's Profit Oil Share
R ≤ 1	30%
1 < R ≤ 2.5	30% - (30%-15.6%)*(R-1)/(2.5-1)
R > 2.5	15.6%

Where, for each block:

$$R = \frac{\text{Cumulative Cost Oil + Cumulative Corporation Share of Profit Oil}}{\text{Cumulative Costs incurred Since 25 February 2003}}$$

Sangaw North

Addax Petroleum's interests in the Sangaw North licence area are governed by a PSC with the KRG effective November 10, 2007. The Sangaw North PSC has an initial exploration period term of five years and imposes minimum work obligations and financial commitments which the Corporation is required to undertake and fund. The Corporation is required to complete the first phase of its work commitments within three years of signing of the PSC.

The PSC for Sangaw North follows the same structure as the Amended Revised Taq Taq PSA in that oil produced under the Sangaw North PSC is notionally allocated to Royalty Oil, Cost Oil and Profit Oil. The calculation of Royalty Oil is based on a rate of 10 per cent of total production. Cost Oil is allocated to the Corporation in such an amount as to enable the recovery of all recoverable costs, up to a maximum of 40 per cent for crude oil and 53 per cent for non-associated natural gas. Profit Oil is the oil remaining after the deduction of Royalty Oil and Cost Oil. Profit Oil is shared between Addax Petroleum and the KRG pursuant to the following sliding scale for each block for crude oil:

R Factor	Addax Petroleum's Profit Oil Share
R ≤ 1	30%
1 < R ≤ 2	30% - (30% - 15%)*(R-1)/(2-1)
R > 2	15%

Where, for each block:

$$R = \frac{\text{Cumulative Cost Oil + Cumulative Corporation Share of Profit Oil}}{\text{Cumulative Costs}}$$

EMPLOYEES

As at December 31, 2008, Addax Petroleum had 864 employees, as set forth in the table below. Contractors and temporary staff are not included.

	Number of Expatriates	Total Number of Employees
Switzerland	n/a	212
Nigeria	29	326
Gabon	15	310
Cameroon	3	12
United Arab Emirates	2	4

All Nigerian employees, other than management employees, are members of the Petroleum and Natural Gas Senior Staff Association of Nigeria (PENGASSAN). Employees in Gabon are subject to a Company Convention (convention d'entreprise) in conformity with the Work Code of Gabon.

CORPORATE SOCIAL RESPONSIBILITY

Corporate Citizenship

Addax Petroleum believes that being a good employer and a responsible corporate citizen are essential to building and sustaining a profitable and growing business. The Corporation takes pride in providing a safe and healthy workplace for its employees and contractors while also providing assistance and benefits to the local communities where the Corporation conducts its oil and gas operations.

Addax Petroleum continued these efforts in 2008. Addax Petroleum's community relations program provides tangible and immediate benefits to the Corporation's local host communities while contributing to the safety and stability of the Corporation's operations.

The Geneva-based Addax Petroleum Foundation, which was established in 2007 by Addax Petroleum, actively developed and extended the Corporation's involvement in social programs in Africa and the Middle East. The Addax Petroleum Foundation is an independent, non-profit foundation, which aims to address the root causes of poverty and make concrete and measurable differences to communities by supporting sustainable projects in four core areas: education, health, community development and the environment. In its first year, the Foundation has built partnerships with non-governmental organizations on nine projects in Benin, Burkina Faso, Egypt, Ethiopia, Madagascar, Mali, Morocco, Niger and Uganda. In late 2008, Addax Petroleum renewed its commitment to provide an annual budget of $1 million to the Foundation. Further detailed information on the Foundation and the projects it supports can be found at www.addaxpetroleumfoundation.org.

Health & Safety

Addax Petroleum continued to experience significant growth in production, development and exploration during 2008. Despite the increased level and intensity of activity, the Corporation's safety record remained among the best in the industry as the Corporation's overall lost time injury rate continued to be well below the industry average.

In 2008, the Corporation continued to develop its HSSE Department and continued to implement the Addax Petroleum HSSE Management System across all of its operating companies. The Corporation's HSSE Department continues to develop and implement programs required to achieve the Corporation's objectives and to provide a robust framework for corporate HSSE The Corporation plans to continue to work with its operating companies to ensure that health and safety remain a top priority in all aspects of the business.

Security

Addax Petroleum has continued to invest significant time and resources into developing proactive and responsible relationships with its host communities, local stakeholders and leaders in order to minimize potential interruptions to the Corporation's business activities. The increase in piracy and criminal activity offshore Nigeria has provided security challenges to the industry as a whole, including the Corporation's offshore operations. There were several serious incidents involving contractors working for Addax Petroleum during 2008.

In February, criminals attacked the premises of an apartment compound used by Addax Petroleum in Lagos. An on duty policeman was shot and killed and a Provincial Guard was seriously injured. Two Addax Petroleum employees were robbed at gunpoint during the incident. This was the first time that Addax Petroleum and its employees were victims of an incident of this nature in Lagos. In June, two contractor support vessels were intercepted by pirates while supporting Addax Petroleum operations in OML123 and OML126. The Autry G vessel on contract to GFL Shipping was attacked resulting in the death of one Nigerian Naval personnel. The MV Mako on contract to Seacor Marine was attacked resulting in one contractor killed. In December, the Oceanix Orion on contract to Work Ships Africa was boarded by pirates and three contractors were kidnapped. They were subsequently released. Also in December, a contracting support vessel MV Falcon Crest contracted to Workships Africa was attacked by pirates near OML 123. During the attack the captain was killed. In all of these cases, Addax Petroleum provided significant incident response support and continues to reiterate the need for sound security strategies while supporting Addax Petroleum's operations.

The Corporation regards these incidents as directed towards opportune targets and not at Addax Petroleum specifically. Notwithstanding this, in 2008 Addax Petroleum commissioned two independent audits on Risk Assessment for Nigeria, which have resulted in continued updates and improvements to security plans. Contractor responsibilities have been reinforced and security plans have been updated to meet current risk. This has included the establishment of three new Security Advisors to Nigeria and the hiring of several new escort vessels to assist the Navy with their national security functions. Addax Petroleum continues to promote stability in the region and continues to lobby both the industry and the Government of Nigeria for a collective and integrated approach to the increase in criminal activity, including piracy, in the region. Since 1998, the Corporation has not had any material unplanned disruptions in production due to civil unrest or security incidents.

Environmental Policies & Programs

In 2008, the Corporation continued to support conservation initiatives directed towards reducing the environmental footprint of its operations, promoting sustainable development and to protect and improve the ecology and biodiversity of countries in which it conducts business through partnerships with regional and national authorities, UN agencies and non-profit organizations. Projects undertaken in 2008 include:

- Two programs with UNITAR (the United Nations Institute for Training and Development): one consists in improving fluvial transportation around the Ogooué and Fernan-Vaz Rivers in Gabon and in Cameroon, and the other consists in facilitating a peaceful transfer of authority on the Bakassi peninsula from Nigeria to Cameroon;
- Two programs administered by the Sahara Conservation Fund – one in Chad and one in Niger – to protect and preserve the addax antelope from which the Corporation takes its name; and
- An international research and education centre for the study of primates, biodiversity research and forest management in the tropical rainforest of Cross River State, Nigeria. The research centre is run by CERCOPAN, a Nigerian environmental non-governmental organization.

Addax Petroleum has also conducted comprehensive Environmental Impact Assessment (EIA) studies ahead of its drilling activities such as those undertaken in Cameroon in 2007 and 2008.

The Corporation also continued to work in 2008 to ensure that it would be able to cease gas flaring in OML124 and OML126 and is currently working with NNPC's National Petroleum Investment Management Services (NAPIMS) on a plan for the cessation of gas flaring in OML123. The Corporation has committed considerable resources towards ceasing gas flaring, has worked diligently throughout 2008 to extinguish its part of the flare, and still expects to be in a position to cease natural gas flaring in the first half of 2009 for OML124 and OML126.

The Corporation continues to refine its environmental policies and programs and regularly consults with local stakeholders and non-governmental organizations to align its programs with local priorities.

Community Relations

Alignment with local priorities has long been a key driver of Addax Petroleum's community relations programs. Since the Corporation first started working in West Africa in 1994, the Corporation has fostered an open dialogue with local community leaders as a means of cultivating relationships based on mutual understanding and trust. This approach has enabled the Corporation to target its support on programs and facilities – schools, roads, clean water systems – that are important to local stakeholders which the Corporation believes has in turn created a sense of goodwill toward the Corporation.

Infrastructure is not the only area of concern for Addax Petroleum; in fact, education has also been a key priority. As such, the Corporation attempts to foster this within host communities in OML123, OML124 and OML126 by offering various scholarship opportunities for post-primary and post-secondary schooling. Additionally, while Nigeria has significant cultural, social and religious diversity, Addax Petroleum has supported a Rugby school initiative that attempts to bridge cultural, social, and religious divides by bringing adults and children aged 9 through 16 from Lagos and nine surrounding states to participate in team sport and to learn the importance of teamwork, responsibility, communication and fun.

In addition, Addax Petroleum has made it a priority to comply with the economic development policies related to the oil and gas industry of the national governments of its host nations. For example, Addax Petroleum was able to comply in 2006 with the Nigerian Government's policy goal of 45 per cent Nigerian content in the oil and gas industry. Addax Petroleum was able to achieve that target in part because it has supported the development of efficient and competitive local companies capable of providing the Corporation with goods and services in all areas of operation.

Also in 2008, the Corporation continued its involvement in three major sponsorships or partnerships:

- The Corporation continues to support the work of UNITAR (the United Nations Institute for Training and Development) on two social and economic development projects in Cameroon and Gabon. In Gabon, the Corporation is supporting a project to improve lake and river transport to the major towns in the territory around the Ogooue and Fernan-Vaz Rivers. In Cameroon, the Corporation is supporting a project inline with the "Greentree Agreement" signed on June 12, 2006 between Cameroon and Nigeria, which defined the terms and conditions of the transfer of authority for the Bakassi peninsula. The project aims to improve the future of the people of Bakassi in respect of their peaceful long-term integration into Cameroon and continued development for their benefit; and
- In Nigeria, Addax Petroleum, in partnership with Lonadek Oil and Gas Consultants, is the platinum sponsor of an important new training and professional development program focused on Nigeria's youth. The program, entitled "Vision 2020: Restoring Hope through Youth Empowerment," focuses on motivating and training young people to pursue professional careers in the oil and gas

industry so that by 2020 they will be able to fill many of the key jobs in the local industry. In 2008 this program benefited 120 people from each of the OML123, OML124 and OML126 communities. At the conclusion of the programs, graduates were awarded a start-up kit which allowed them to begin their own business in their chosen trade.

- In Nigeria, Addax Petroleum continued its partnership with Project Genesis. In 2008, the “Kick Out Malaria” program focused on providing malaria checks, treatments and preventative measures to host communities. By the project’s end, more than 7,000 people had received treated mosquito nets, blood pressure checks, malaria checks and medications for those infected with the virus.

These types of programs are not only worthwhile because of the benefits they provide to indigenous populations but also because they are a concrete expression of the Corporation’s commitment to those countries where it operates.

RISK FACTORS

Addax Petroleum is exposed to a number of risks inherent in the exploration for, development and production of oil and gas. This section describes the risks and other matters that would most likely influence an investor’s decision to purchase securities of Addax Petroleum. Additional risks and uncertainties not presently known to the Corporation or currently deemed immaterial may also impair business and affect the price of Addax Petroleum’s Common Shares. If any of the risks or uncertainties described in this AIF actually occurs, the Corporation's business prospects, results of operations or financial condition could be materially adversely affected. See also “Reader Advisory Regarding Forward Looking Statements”.

Risks Related to the Business of the Corporation

The Corporation’s business and the jurisdictions in which it operates

Numerous factors beyond the Corporation’s control may affect the success of the Corporation’s business. These include local, national and international economic, legal and political conditions. The Corporation’s business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The operations of the Corporation in certain developing countries, such as Nigeria, Cameroon, Gabon and Iraq, expose it to potential civil unrest and political or currency risks. In particular, recent escalation in civil unrest in Nigeria and Iraq may pose a threat to the operations of the Corporation in those countries and any intensification in the level of civil unrest may have a material adverse effect on the Corporation’s business, results of operations or financial condition.

Existing and Future financing

The Corporation has existing debt facilities including a $1.6 billion senior secured revolving debt facility and a $500 million senior unsecured revolving debt facility, which are both drawn upon when necessary. The $1.6 billion senior revolving debt facility is in the form of a borrowing base loan. There can be no assurance that the Corporation will be able to maintain a sufficient borrowing base, and as a result the Corporation may be required to repay some or all of the drawn amounts or lose the ability to draw on the unutilized amounts. Both debt facilities also contain certain debt ratio covenants and there can be no assurance that the Corporation will be able to maintain such covenants, resulting in the potential reduction or withdrawal of one or both of the debt facilities. There can also be no assurance that prevailing market conditions would allow for the refinancing or extension of one or both debt facilities when they come due, which could have a material adverse effect on the Corporation’s business and financial condition.

Depending on future exploration, development, production or acquisition plans, the Corporation may require additional financing. The ability of the Corporation to arrange such financing in the future will depend in part upon prevailing market conditions as well as the business performance of the Corporation. Although the Corporation does not currently anticipate the need to access financing, there can be no assurance in the current market conditions that debt financing will be readily available. In addition, if the Corporation’s revenues or reserves decline, it may not have the capital necessary to undertake or complete future drilling programs and there can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Transactions financed partially or wholly with debt may increase the Corporation’s debt levels above industry standards. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation’s business and financial condition. If additional financing is raised by the issuance of shares from treasury of the Corporation, control of the Corporation may change and shareholders may suffer dilution.

Ability to find, develop and acquire additional reserves

The Corporation’s future oil reserves and production, and therefore its cash flows and earnings, are highly dependent upon the Corporation developing and increasing its current reserve base. Without the addition of reserves through exploration, acquisition or development activities, the Corporation’s reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, the

Corporation's ability to make the necessary capital investments to maintain and expand its oil reserves will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Operating hazards and uninsured risks

The Corporation is subject to all of the operating risks normally associated with the exploration for, and the production, storage, transportation and marketing of oil and gas, including blowouts, explosions, fire, gaseous leaks, migration of harmful substances and oil spills, any of which could cause personal injury, result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, the Corporation's operations are subject to all of the risks normally incident to drilling of oil and natural gas wells and the operation and development of oil and gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

The Corporation's production facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, vessel collision and damage from severe storms or other severe weather conditions. The offshore drilling conducted by the Corporation involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The Corporation, and operators of properties in which it has an interest, maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability or that the Corporation will be able to obtain insurance to cover such risks. For example, the Corporation does not have business interruption insurance in place and, therefore, it will suffer losses as a result of a shut-in or cessation in production. The occurrence of an unfavourable event not fully covered by insurance could have a material adverse effect on the Corporation's financial condition, results of operations and cash flows. Furthermore, insurance may not continue to be available at a reasonable cost or at all.

Oil and gas operations and production

Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations. Certain of the Corporation's oil and gas properties are operated by third parties or may be subject to operating committees controlled by national oil companies and, as a result, the Corporation has limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties. The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The ability of the Corporation to market any natural gas discovered may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Corporation is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities, including the ability to acquire space on pipelines to deliver natural gas to commercial markets, and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Corporation is also subject to a variety of waste disposal, pollution control and similar environmental laws. The oil and gas industry is subject to varying environmental regulations in each of the jurisdictions in which the Corporation operates and which it may operate.

Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently and oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures. The Corporation may be responsible for abandonment and site restoration costs.

Exploration and development

The Corporation's oil and natural gas exploration may involve unprofitable efforts, including dry wells as well as productive wells that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations and various field operating conditions may adversely affect the production from successful wells.

Whether the Corporation ultimately undertakes an exploration or development project depends upon a number of factors, including the availability and cost of capital, current and projected oil and gas prices, receipt of government approvals, access to the property, the costs and availability of drilling rigs and other equipment, supplies and personnel necessary to conduct these operations, success or failure of activities in similar areas and changes in the estimates to complete the projects.

The Corporation will continue to gather data about its new venture opportunities and other projects. Additional information could cause the Corporation to alter its schedule or determine that a new venture opportunity or project should not be pursued, which could adversely affect the Corporation's prospects.

Under its Production Sharing Contracts and agreements, the Corporation finances exploration, development and operations and the related facilities and equipment and will only recover its costs if there is successful production in accordance with the terms of the Production Sharing Contracts and agreements.

Title to properties

There is no guarantee that an unforeseen defect in title, changes in laws or change in their interpretation or political events will not arise to defeat or impair the claim of the Corporation to its properties which could result in a material adverse effect on the Corporation, including a reduction in revenue.

Project completion

The Corporation's current operations are, and future operations will be, subject to approvals of governmental authorities and, as a result, the Corporation has limited control over the nature and timing of development and exploration of oil and natural gas properties or the manner in which operations are conducted on such properties.

The Corporation's Production Sharing Contracts, and other contracts with governments and government bodies to explore and develop the properties, are subject to specific requirements and obligations. If the Corporation fails to satisfy such requirements and obligations and there is a material breach of such contracts, such contracts could, under certain circumstances, be terminated. The termination of any of the Corporation's contracts granting rights in respect of the properties would have a material adverse effect on the Corporation, including the Corporation's financial condition. In additional, project delays can be affected by availability of processing capacity or pipeline capacity, availability of drilling and other equipment, and unexpected cost increases. The rate of increase in the cost of materials and services relative to declining commodity prices has become a significant factor affecting project planning and economics.

Dependence on management and key personnel

The Corporation is highly dependent upon its executive officers and key employees, and the success of the Corporation will be largely dependent upon the performance of such officers and key employees. In particular, the Corporation's Chief Executive Officer, Jean Claude Gandur, has a number of key relationships that are important to the Corporation's business. The unexpected loss of the services of Mr. Gandur or other executive officers or key personnel could have a material adverse effect on the Corporation. The Corporation does not maintain key man life insurance on any of its employees. In assessing the risk of an investment in the Common Shares, potential investors should recognize that they are relying on the ability and integrity of the management of the Corporation.

Marketing oil and natural gas

The marketability of any oil and natural gas acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The Corporation's ability to market its natural gas may depend upon its ability to acquire space on pipelines to deliver oil and natural gas to commercial markets. For example, the Corporation's produced associated natural gas in Nigeria, is currently flared or reinjected, as there is no established market in which to sell the natural gas, nor does the Corporation have the necessary facilities to capture or transport natural gas.

The Corporation may also be affected by deliverability uncertainties related to the proximity of its other reserves to pipelines and processing facilities, the availability of or operational problems with such pipelines and facilities, and as a consequence of extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Affiliated company marketing agreement

In conducting its business, the Corporation will continue to rely on Addax Energy to purchase and sell the crude oil the Corporation produces under the Crude Oil Supply Agreements. Both the Corporation and Addax Energy have the right to terminate any of the Crude Oil Supply Agreements should the counterparty a) commit any material breach or persistent breaches of the Crude Oil Supply Agreements, b) become insolvent under the provisions of any relevant law or c) fail to pay any monies owing to the party within 7 days of being requested to do so. The Corporation also has the right to terminate any of the Crude Oil Supply Agreements on not less than ninety days prior written notice to Addax Energy at the Corporation's discretion. If the Corporation's agreements with Addax Energy terminate for any reason, the Corporation may be unable to enter into a relationship with another purchaser and seller of its crude oil on a timely basis or on acceptable terms, which could materially adversely affect the Corporation's business, results of operations or financial condition.

Shared trademark and trade name

The Corporation shares a trademark and a trade name with AOG and many of AOG's subsidiaries. AOG engages in petroleum trading and distribution, and mining activities throughout Africa and in Eastern Europe, and it has subsidiaries, local branches and commercial representation bureaus throughout Africa and in Europe and Asia. Many of the countries in which AOG operates have experienced high levels of governmental and business corruption and other illegal activity. AOG and its officers, directors and employees have been and may in the future be, the subject of press speculation, governmental investigations and other accusations of corrupt practices or other illegal activities, including improper payments to individuals of influence.

Pursuant to the Trademark Agreement, the Corporation intends to continue identifying itself using names and logos that indicate a relationship with AOG. Given that the Corporation shares a trademark and trade name with AOG and with many members of the AOG group, any adverse development affecting the trademark, trade name or reputation of any of those companies could have a material adverse effect on the business, goodwill or reputation of the Corporation.

Labour or other unplanned production disruptions

The Corporation has a significant number of staff belonging to certain trade unions which have a record of occasional industrial action. The presence of trade unions may limit the Corporation's flexibility in dealing with its staff. If there is a material disagreement between the Corporation and its trade unions, the Corporation's operations could suffer an interruption or shutdown that could have a material adverse effect on the Corporation's business, results of operations or financial condition.

The Corporation's growth and development

The Corporation has experienced significant growth and development in a relatively short period of time and expects to continue to grow as production increases from its oil reserves. Management of that growth requires, among other things, stringent control of financial system and operations, the continued development of management controls, the training of new personnel and continued access to funds to finance this growth. Failure to successfully manage the Corporation's expected growth and development could have a material adverse effect on the Corporation's business, results of operations or financial condition.

Litigation

From time to time, the Corporation is subject to litigation arising out of its operations. Damages claimed under such litigation may be material or may be indeterminate, and the outcome of such litigation may materially impact the Corporation's business, results of operations or financial condition. While the Corporation assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Corporation's business.

The Corporation's diversification and acquisition strategies

The Corporation intends to acquire additional oil and gas properties. Although the Corporation performs a review of properties prior to acquiring them that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Corporation will focus its due diligence efforts on higher valued properties and will sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. The Corporation may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interests in properties on an "as is" basis. In addition, competition for the acquisition of prospective oil properties is intense, which may increase the cost of any potential acquisition. To date the Corporation's exploration and development activities have principally been based in Nigeria, Gabon and nearby areas in West Africa as well as the Kurdistan Region of Iraq, and the Corporation's limited presence in other regions may limit its ability to identify and complete acquisitions in other geographic areas. There can be no assurance that any acquisition by the Corporation will be successful.

Commodity, interest rate and currency hedging activities

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices, interest rates and exchange rates. The Corporation monitors its exposure to these fluctuations and, where appropriate, it has in the past used derivative financial instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage its exposure to these risks. While the Corporation does not maintain a defined hedging program, it may determine it appropriate to enter into additional derivative financial instruments or physical delivery contracts to reduce its exposure. The terms of these derivative instruments may limit the benefit of commodity price increases, changes in interest rates and currency value which are otherwise favourable to the Corporation and may result in financial or opportunity loss due to delivery commitments and counterparty risks associated with the contracts. Utilization of derivative financial instruments may introduce increased volatility into the Corporation's reported net earnings. If the Corporation enters into hedging arrangements, it may suffer financial loss if it is unable to commence operations on schedule or is unable to produce sufficient quantities of oil to fulfill its obligations.

Most of the Corporation's revenue is received in or referenced to US dollar denominated prices, while the majority of the Corporation's expenditures are denominated in US dollars, Nigerian naira, Swiss francs, Euros and Central African CFA francs. The Corporation's accounts are prepared in United States dollars and dividends, if paid, will be paid in Canadian dollars. The Corporation is subject to inflation in the countries in which it operates and fluctuations in the rates of currency exchange between the United States dollar and these currencies. While such inflation does not currently impact the Corporation, future fluctuations may materially affect the Corporation's business, results of operations or financial condition. Consequently, construction, exploration, development, administration and other costs may be higher than the Corporation anticipates. In addition, the Corporation's senior debt facilities are denominated in United States dollars. Fluctuations in the exchange rate between the US dollar and other currencies could result in realized and unrealized losses on this and other US dollar denominated long-term debt. Any increase in relevant interest rates will increase the amount the Corporation pays to service debt.

Joint ventures

The Corporation has entered into joint ventures in respect of its Cameroon, Gabon, JDZ, Okwok and Kurdistan Region of Iraq interests. The Corporation may suffer unexpected costs or other losses if a joint venture partner does not meet its obligations. It is also possible that the interests of the Corporation and those of its joint venture partners are not aligned resulting in project delays, additional costs or disagreements, which could adversely affect the Corporation's business.

Risks relating to the petroleum industry

Volatility of commodity prices

The Corporation's business, results of operations or financial condition and future growth are substantially dependent on the prevailing prices for its petroleum production. Historically, the markets for petroleum have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes to the demand for oil, whether the result of uncertainty or a variety of additional factors beyond the control of the Corporation, including actions taken by OPEC and its adherence to agreed production quotas, war, terrorism, government regulation, social and political conditions in oil producing countries generally and in Nigeria, Gabon and Iraq specifically, economic conditions, prevailing weather patterns and the availability of alternative sources of energy. It is impossible to accurately predict future crude oil and natural gas price movements. Crude oil and natural gas prices may not remain at their current levels, and any further substantial decline in the price of petroleum could have a material adverse effect on the Corporation's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Corporation's properties, its planned level of spending for exploration and development and the level of its reserves. No assurance can be given that commodity prices will be sustained at levels which will enable the Corporation to operate profitably.

Any substantial decline in oil prices may also require the Corporation to write down certain of its assets. Under Canadian GAAP, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit", which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, the Corporation must charge the amount of the excess against earnings. As oil prices decline, the Corporation's net capitalized cost may approach or exceed this cost ceiling, resulting in a charge against earnings. While a write down would not directly affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit the Corporation's ability to borrow funds or comply with covenants contained in current or future credit agreements or other debt instruments.

Increases in materials and services costs and demand for drilling and related equipment

The Corporation relies on oil field suppliers and contractors to provide materials and services in conducting the exploration and production business of the Corporation. Any substantial increase in the world-wide prices of commodities, such as steel, and competitive pressures on the oil field suppliers could result in a material increase of costs for the materials and services required by the Corporation to conduct its business. In addition, due to the high global demand, the cost of oil field services and goods increased significantly in recent years compared to prior years and remains high notwithstanding the reduction in oil prices in the second half of 2008. Future increases in costs could have a material adverse effect on the Corporation's operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Corporation's properties, its planned level of spending for exploration and development and the level of its reserves. No assurance can be given that prices for materials and services will be sustained at levels which will enable the Corporation to operate profitably.

Oil and natural gas development and exploration activities are dependent on the availability of drilling and related equipment in the particular areas where such activities are conducted. Demand for limited equipment such as drilling rigs or access restrictions may affect the availability of such equipment to the Corporation and may delay its development and exploration activities. In the areas in which the Corporation operates there is significant demand for drilling rigs and other equipment. Failure by the Corporation to secure necessary equipment could adversely affect the Corporation's business, results of operations or financial condition.

Environmental laws and regulations

All aspects of the oil and gas business are subject to extensive national, state, and local environmental laws and regulations in jurisdictions in which the Corporation operates. These laws and regulations are of general application and apply to the Corporation and other companies and enterprises in the same industry, setting various standards regulating health and environmental quality, providing for civil and criminal penalties and other liabilities for the violation of such standards and establishing in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that the Corporation will not incur substantial financial obligations in connection with environmental compliance.

Significant liability could be imposed on the Corporation for damages, clean-up costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of property purchased by the Corporation, acts of sabotage or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on the Corporation. Moreover, the Corporation cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Corporation for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Corporation.

As a party to various Production Sharing Contracts and agreements, the Corporation may have an obligation to restore producing fields to a condition acceptable to the authorities at the end of these fields' commercial lives. Each party to such contracts or concession is typically liable for its share of the cost of decommissioning infrastructure installed under that contract or concession. In respect of the Corporation's producing properties that are located offshore, the costs to decommission offshore wells may be substantial. These costs are payable at a time when assets are no longer generating cash flow. Although the Corporation makes an accounting provision for decommissioning and site restoration costs, there are no immediate plans to establish a reserve account for these potential costs in respect of any of the Corporation's current properties or facilities. Rather, the costs of decommissioning are expected to be paid from the proceeds of production in accordance with the practice generally employed in onshore and offshore oilfield operations. There can, however, be no assurance that the proceeds from production will be sufficient to meet the costs of decommissioning at the time when required to be incurred. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on the Corporation's financial position.

The Nigerian Government has announced what is commonly referred to as "Flares Down," a policy that will require petroleum producers to reduce or eliminate the amount of natural gas that is flared in petroleum production. To date the Nigerian Government has not enacted any legislation implementing the policy. Consequently, no assurances can be given that the Corporation will be able to comply with any such future legislation.

Estimates of reserves and resources and actual production, revenues and expenditures

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and prospective and contingent resources and cash flows to be derived therefrom, including many factors beyond the control of the Corporation. The reserves, resources and cash flow information set forth in this AIF represent estimates only. In general, estimates of economically recoverable oil reserves and the future net cash flow therefrom are based on a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates (which have inherent uncertainties), historical production from the properties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil reserves attributable to any particular group of properties, the classification of such reserves based on risk recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to the Corporation's reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variation, which may be material, in the estimated or actually recovered reserves.

The present value of estimated future net cash flows referred to herein should not be construed as the current market value of estimated proved oil reserves attributable to the Corporation's properties. The estimated discounted future cash flow from proved reserves are based upon price and cost estimates, which may vary from actual prices and costs and such variance could be material. Actual future net cash flows will also be affected by factors such as the amount and timing of actual production, supply and demand for oil, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Highly competitive nature of the oil and gas industry

The oil and gas industry is intensely competitive in all its phases. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas, including oil and gas companies that possess greater technical, physical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on an international basis. The Corporation also competes with other companies to attract and retain experienced skilled management and oil professionals. If the Corporation is unsuccessful in competing against other companies, its business, results of operations or financial condition would be materially adversely affected. .

Risks relating to the Corporation's countries of operation or future operations

Political, economic and other risks

The Corporation's current oil production activities are located entirely in Nigeria and Gabon. It is also currently pursuing exploration and development activities in Cameroon, the JDZ and the Kurdistan Region of Iraq. Exploration and development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political considerations such as the risks of war, actions by terrorist or insurgent groups, community disturbances, expropriation, nationalization, renegotiation, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation thereof, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls, and foreign governmental regulations that favour or require the awarding of contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Any of these or similar factors could have a material adverse effect on the Corporation's business, results of operations or financial condition. If a dispute arises in connection with foreign operations, the Corporation may be subject to the exclusive jurisdiction of foreign courts or foreign arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of Canada.

Under the International Court of Justice ruling of October 2002, the border between Nigeria and Cameroon was fixed such that a part of OML123, including the Bogi Platform, is now located in Cameroon. On June 12, 2006, the presidents of Nigeria and Cameroon signed an agreement which provides for the withdrawal of Nigerian troops within 60 days from the Bakassi Peninsula, with a possible 30 day extension. However, previous agreements to finalize the International Court of Justice's decision have fallen through, including one which was to have seen the final transfer of authority from Nigeria to Cameroon take place between June 15 and September 15, 2004. Accordingly, the Corporation's business and financial affairs could be materially affected by any actions taken in contravention of the agreement reached on June 12, 2006.

Addax Petroleum has continued to monitor the impact of ongoing intermittent Turkish military action in the border region of Turkey and the Kurdistan region of Iraq since February 2008. While the situation is under constant review, Addax Petroleum does not anticipate an impact to capital expenditures or operations in the Kurdistan Region of Iraq in the short-term.

Risk of criminal or terrorist actions

Oil and gas companies operating in countries such as Nigeria, Gabon, Cameroon and Iraq may be targets of criminal or terrorist actions. Criminal or terrorist action against the Corporation, its properties or facilities could have a material adverse effect on the Corporation's business, results of operation or financial condition. In addition, the possible threat of criminal or terrorist actions against the Corporation could have a material adverse effect on the ability of the Corporation to raise capital or to adequately staff its operations or could substantively increase the costs of doing so. In February 2008 an on-duty police officer was shot and killed and two Addax Petroleum employees were robbed at gunpoint during an incident at an apartment compound in Lagos. In June 2008, two contractor support vessels were intercepted by pirates while supporting Addax Petroleum operations in OML123 and OML126, resulting in the deaths of one Nigerian Naval personnel and one contractor. In December, a contractor support vessel was boarded by pirates and three contractors were kidnapped. They were subsequently released. Also in December, a contractor support vessel was attacked by pirates near OML 123. During the attack the captain was killed. While the Corporation regards each of these incidents as isolated events that it believes are not indicative of the quality of its relationships with the local communities, no assurance can be given that similar incidents will not occur in the future.

Relinquishment obligations under applicable legislation and the terms of PSCs

Pursuant to the terms of the Nigeria PSCs for OML123, OML124, OML126 and OML137, Addax Petroleum is required, not later than five years from the effective date of the PSC, to relinquish 50 per cent of the contract area (excluding any areas in which petroleum had been discovered in commercial quantities) pursuant to mutual agreement between NNPC and the Corporation. Subsequent to the date required for such relinquishment, the OPLs under which the Corporation held the areas were converted to OML123, OML124, OML126 and OML137. The conversions of OML123, OML124 and OML126 did not include any relinquishment of the respective contract areas. The Corporation has obtained legal advice to the effect that, as the conversion from the previous OPLs into OML123, OML 124 and OML126 required the consent of NNPC, the obligation under the PSC to relinquish the area is no longer effective. However, there is a risk that NNPC could in the future request such relinquishment. In the case of OML137, 50 per cent of the contract area was relinquished upon conversion from the previous OPL.

In addition, in accordance with the *Petroleum Act*, 50 per cent of the area covered by an OML must be relinquished within ten years of the date of grant of the OML. OML123 and OML124 were granted in July 2002. OML126 was granted effective November 2004 and OML137 was granted in 2007. All the licences contain such relinquishment provisions. There can be no assurance that the area proposed by the Corporation for relinquishment will be accepted by the government, and there is a risk that such relinquishment may necessarily contain reserves already booked by the Corporation, leading to a restatement of its reserves.

The Ngosso licence contains a change of control provision which provides that "if [the State], pursuant to Article 34 of the Petroleum Regulations shall have become aware of changes in the factors constituting control of the Contractor or of an entity comprising Contractor, [the State] may, within 90 days order the latter to take all necessary steps in order to terminate the operations which led to such changes". Accordingly, any change of control in the Corporation could have an adverse effect on the Corporation's operations in Cameroon.

In addition, certain Gabonese Production Sharing Contracts may contain mandatory relinquishment provisions upon entering into subsequent exploration phases.

Crime and governmental or business corruption

The Corporation operates and conducts business in countries or regions which have experienced high levels of governmental and business corruption and other criminal activity. The Corporation and its officers, directors and employees have been, and may in the future be, the subject of press speculation, government investigations and other accusations of corrupt practices or illegal activities, including improper payments to individuals of influence. The Nigerian Government is reported to be conducting corruption and other investigations into the oil industry in Nigeria. The Corporation is not aware of any current investigations specific only to the Corporation or any adverse findings against it, its directors, officers or employees or any member of the AOG group.

Although the Corporation's policy mandates strict compliance with internal policies and applicable laws which prohibit corrupt payments to government officials or other businesses or persons, there is no assurance that such internal policies and procedures have been or will be adhered to by its employees. Findings against the Corporation, its directors, officers or employees, or their involvement in corruption or other illegal activity could result in criminal or civil penalties, including substantial monetary fines, against the Corporation, its directors, officers or employees. Any government investigations or other allegations against the Corporation, its directors, officers or employees, or finding of involvement in corruption or other illegal activity by such persons, could significantly damage the Corporation's reputation and its ability to do business, including affecting its rights under the various PSCs or through the loss of key personnel, and could materially adversely affect its financial condition and results of operations. Furthermore, alleged or actual involvement in corrupt practices or other illegal activities by AOG, the joint venture partners of the Corporation or others with whom the Corporation conducts business, could also significantly damage the Corporation's reputation and business and materially adversely affect the Corporation's financial condition and results of operations.

Uncertainty regarding interpretation and application of foreign laws and regulations

The jurisdictions in which the Corporation operates may have less developed legal systems than more established economies, which may result in risks such as: (i) effective legal redress in the courts of such jurisdictions being more difficult to obtain, whether in respect of a breach of law or regulation, or an ownership dispute; (ii) a higher degree of discretion on the part of governmental authorities; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions; or (v) relative inexperience of the judiciary and courts in such matters. Enforcement of laws in some of the jurisdictions in which the Corporation operates may depend on and be subject to the interpretation placed upon such laws by the relevant local authority, and such authority may adopt an interpretation of an aspect of local law which differs from the advice that has been given to the Corporation. There can be no assurance that the Corporation's contracts, joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of and enforcement of such arrangements in these jurisdictions. In certain jurisdictions, the commitment of local businesses, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain and may be susceptible to revision or cancellation, and legal redress may be uncertain or delayed.

In the countries in which the Corporation does business, the state generally retains ownership of the minerals and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, the Corporation's operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges to a greater extent than would be the case if its operations were largely in countries where mineral resources are not predominantly state owned. In addition, transfers of interests typically require government approval, which may delay or otherwise impede transfers, and the government may impose obligations on the Corporation to complete minimum work within specified timeframes. In the future, the Corporation may extend its interests in operations to other countries where similar circumstances may exist.

The legislative framework for the oil and gas industry in Iraq is in the early stages of development and it is not certain how the provisions of the recently adopted Iraqi constitution and proposed Federal Oil Law will be interpreted and applied. Unfavourable interpretations or applications of the Iraqi constitution or the legislative framework with respect to the oil and gas industry could have a materially adverse effect on the Corporation's interests in Iraq.

Compliance with foreign regulatory regimes

The Corporation is subject to extensive government laws and regulations governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and many other aspects of the oil business.

Although the Corporation believes it has good relations with the current governments of Nigeria, Gabon, Cameroon, Iraq and the Kurdistan Region of Iraq, there can be no assurance that the actions of present or future governments in these countries, or of governments of other countries in which the Corporation may operate in the future, will not materially adversely affect the business or financial condition of the Corporation.

Production constraints and export quotas

Nigeria and Iraq are members of OPEC, and the Corporation may operate in other OPEC-member countries in the future. Production in OPEC-member countries can be constrained from time to time by OPEC production quotas. In Nigeria, NNPC allocates production quotas among oil producers in Nigeria based on the aggregate of the technical production limits per well for a producer as negotiated between the producer and the Nigerian government. If the aggregate of all the producers' technical production limits exceeds Nigeria's OPEC quota, the production allocations among the producers are reduced pro rata. The Corporation has historically exceeded its production allocation but has applied for and been granted additional quota from the Nigerian government for all of its excess oil production. There can be no assurance that if the Corporation exceeds its allocated quota in the future that it will continue to receive additional quota from the Nigerian government.

In addition to OPEC production quotas, oil producing countries can also implement export quotas. The Corporation may be constrained in exporting oil that it produces in the future due to the imposition of export quotas.

US government imposed sanctions

US economic sanctions may be imposed on US holders of Common Shares or the Corporation in connection with future operations in countries subject to US economic sanctions, such as Iran. To date, the Corporation has only had discussions with the Iranian national oil company regarding certain projects. Two US sanctions programs, the Iranian Transactions Regulations ("**ITR**") and the Iran and Libya Sanctions Act ("**ILSA**"), may potentially apply to the Corporation's future activities in Iran if the Corporation decides to undertake substantive activities in that country.

The ITR, which are administered by the Office of Foreign Assets Control ("**OFAC**") of the US Treasury Department, apply only to US persons and thus would not apply to the Corporation. However, the ITR may apply to US holders of Common Shares. The Corporation has taken steps it feels are sufficient to mitigate the risk to US holders but there can be no assurance that such steps will be successful. If the OFAC takes a different view of these steps and pursues enforcement of the ITR, US holders may be subject to a range of civil and criminal penalties. The imposition of such penalties may have a material adverse effect on the price of the Common Shares.

The ILSA grants the US President authority to impose sanctions against persons or entities found by the President to have knowingly made investments in Iran's petroleum industry of $20 million or more in any twelve month period. Sanctions could include restrictions on obtaining credit from US financial institutions and the US export import bank and on the ability of the Corporation to procure goods, services and technology from the US. To date, the Corporation has not invested the requisite amount in Iran to trigger ILSA sanctions. Additionally, the Corporation understands that the US government has not yet imposed any sanctions under ILSA, despite having a number of foreign investment projects in Iran under investigation.

The Corporation may in the future invest sufficient money in activities in Iran to trigger ILSA and cannot predict future interpretation of ILSA by the US government regarding any such future activities. It is possible that the US President may determine that these future activities constitute violations of ILSA and subject the Corporation to sanctions. The imposition of sanctions could have an adverse impact on the Corporation's business, results of operations or financial condition.

Other Risks

The controlling shareholder and President and Chief Executive Officer of the Corporation are able to exercise significant control over the affairs of the Corporation

As of the date of this AIF, AOG Holdings BV owns and controls 55,241,829 Common Shares representing approximately 35.28 per cent of the aggregate voting shares of the Corporation. AOG Holdings BV is an indirect wholly owned subsidiary of AOG which is indirectly controlled by Jean Claude Gandur, the President and Chief Executive Officer of the Corporation. This allows AOG Holdings BV, and thereby Jean Claude Gandur, to control substantially all the actions taken by the shareholders of the Corporation, including the election of directors. AOG Holdings BV, and thereby Jean Claude Gandur, currently has sufficient voting power to, among other things, delay, deter or prevent a change in control of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation and limit the amount certain investors may be willing to pay for the Common Shares.

Certain directors and senior management of the Corporation hold positions with AOG and other companies, some of which operate in the petroleum industry. These other positions could create, or appear to create, potential conflicts of interest when these directors and senior management are faced with decisions that could have different implications for the Corporation and their other business interests. In the past, the Corporation has appointed committees of independent directors to evaluate opportunities where conflicts of interest exist or are perceived to exist, and the Corporation will continue to deal with conflicts in this fashion. Although the Corporation expects that such conflicts will be handled in accordance with the CBCA and its corporate governance policies, there is no assurance that all conflicts will be adequately addressed.

The Corporation has entered into an agreement with AOG in which AOG has agreed to conduct its upstream petroleum business entirely through the Corporation, to not compete with the Corporation in such business and to offer the Corporation any upstream petroleum business opportunities made available to AOG, in each case so long as AOG and Jean Claude Gandur together own not less than 25 per cent of the issued and outstanding Common Shares. It is nonetheless possible that other conflicts could arise that may ultimately be resolved in a manner unfavourable to the Corporation.

Sales of Common Shares by controlling and significant shareholder(s) could have an adverse effect on the price of the Common Shares.

During 2006 and subsequent to the IPO, AOG proposed a reorganization of AOG that gave shareholders the ability to exchange their AOG shares for Common Shares of Addax Petroleum and other consideration. Certain shareholders of AOG elected to exchange their AOG shares in return for approximately 46.1 million Common Shares. In addition, in 2007 AOG entered into agreements with various shareholders whereby AOG exchanged approximately 8 million Common Shares of Addax Petroleum in return for redemption of AOG shares. As of the date of this AIF, the shareholders of AOG who elected to exchange their AOG shares for Common Shares have all received their Common Shares and are not subject to any contractual restrictions imposed by AOG or Addax Petroleum regarding the sale of their Common Shares. The Corporation cannot predict whether substantial numbers of the Common Shares received by AOG shareholders will be sold in the open market. Sales of a large number of the Common Shares in the public markets, or the potential for such sales, could decrease the trading price of the Common Shares and could impair the Corporation's ability to raise capital through future offerings of Common Shares.

As of the date of this AIF, AOG Holdings BV owns and controls 55,241,829 Common Shares of Addax Petroleum representing approximately 35.28 per cent of the issued and outstanding Common Shares. AOG Holdings BV is an indirect wholly owned subsidiary of AOG which is indirectly controlled by Jean Claude Gandur, the President and Chief Executive Officer of Addax Petroleum. The Corporation cannot predict whether AOG Holdings BV will sell any of the Common Shares it holds in the open market. Sales by AOG Holdings BV of a large number of the Common Shares in the public markets, or the potential for such sales, could decrease the trading price of the Common Shares and could impair the Corporation's ability to raise capital through future offerings of Common Shares.

The Corporation's holding company structure

The Corporation holds all of its assets in its wholly owned subsidiary, APHL. In the event of insolvency, liquidation or other reorganization of APHL, the holders of the Common Shares will have no right to proceed against the assets of APHL or to cause the liquidation or bankruptcy of the company under applicable bankruptcy laws. Creditors of APHL would be entitled to payment in full from such assets before the Corporation, as a shareholder, would be entitled to receive any distribution therefrom. Claims of creditors of APHL will have priority with respect to the assets and earnings of APHL over the claims of the Corporation, except to the extent that the Corporation may itself be a creditor with recognized claims against APHL ranking at least *pari passu* with such other creditors, in which case the claims of the Corporation would still be effectively subordinate to any mortgage or other liens on the assets of APHL and would be subordinate to any indebtedness of APHL.

STATEMENT OF RESERVES AND OTHER OIL AND GAS DATA

All of Addax Petroleum's interests in its properties have been evaluated by NSAI as of December 31, 2008. The tables below summarize the Corporation's petroleum reserves, other resources not currently classified as reserves, and the present value of future net revenue associated with Addax Petroleum's reserves based on forecast prices and costs assumptions and are presented in accordance with National Instrument 51-101 — *Standards of Disclosure for Oil and Gas Activities*. The tables summarize the data contained in the Reserves Report and, as a result, may contain slightly different numbers than the Reserves Report due to rounding. Future net revenue values, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of Addax Petroleum's petroleum reserves provided herein are estimates only and there is no assurance that the estimated reserves will be recovered. Actual petroleum reserves may be greater than or less than the estimates provided herein. The estimates of reserves and future net revenue for individual properties included in this report may not reflect the same confidence level as estimates of revenue for all properties, due to the effects of aggregation. The Reserves Report is based on data supplied by Addax Petroleum and on NSAI's opinions of reasonable industry practice.

The Corporation's reserves are comprised of light to medium oil in Nigeria, Gabon and the Kurdistan Region of Iraq. The Corporation's Nigerian Production Sharing Contracts do not include the right to produce and sell natural gas and therefore the Corporation's reserves evaluations do not include any natural gas reserves. The Production Sharing Contracts in Nigeria and the Production Sharing Agreement in the Kurdistan Region of Iraq contain natural gas utilization clauses which permit the Corporation to participate in commercial natural gas development if and when it occurs. The Corporation's Production Sharing Contracts in Gabon treat commercial natural gas in effectively the same manner as crude oil.

The Corporation also undertakes exploration operations on its properties in Cameroon (Ngosso and Iroko), the JDZ, Offshore Nigeria (OPL227 and OPL291), Onshore and Offshore Gabon (Epaemeno, Gryphon Marin, Ibekelia, Iris Marin and Kiarsseny) and the Kurdistan Region of Iraq (Sangaw North) for which there are no reserves as at December 31, 2008.

The Statement of Reserves Data and Other Oil and Gas Information (the "Statement") is dated March 4, 2009. The information provided in the Statement has an effective date of December 31, 2008 and a preparation date of January 29, 2009.

Reserves

Oil Reserves and Future Net Revenues as at December 31, 2008(8)(9)(10)(12)(13)(15)(16)

	Crude Oil Reserves (7)		Estimated Net Present Values of Future Net Revenue Before Taxes Discounted at					Estimated Net Present Values of Future Net Revenue After Taxes(14) Discounted at				
	Gross	Net	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(MMbbl)		*($million)*					*($million)*				
Proved(1)												
Developed Producing(2)												
Nigeria	82.0	74.9	4,053	3,694	3,401	3,157	2,951	1,679	1,548	1,439	1,348	1,270
Gabon	20.0	12.5	457	419	387	361	338	412	381	354	331	311
Kurdistan Region of Iraq	—	—	—	—	—	—	—	—	—	—	—	—
Total Developed Producing	**102.0**	**87.4**	**4,510**	**4,113**	**3,788**	**3,517**	**3,288**	**2,091**	**1,928**	**1,793**	**1,679**	**1,582**
Developed Non-Producing(3)												
Nigeria	11.8	10.4	702	583	492	422	366	213	178	151	130	113
Gabon	8.4	5.0	293	240	202	174	152	265	222	189	164	144
Kurdistan Region of Iraq	—	—	—	—	—	—	—	—	—	—	—	—
Total Developed Non-Producing	**20.3**	**15.4**	**995**	**823**	**694**	**595**	**518**	**478**	**399**	**340**	**294**	**258**
Undeveloped(4)												
Nigeria	39.9	34.7	1,433	1,136	912	740	606	440	333	251	187	137
Gabon	38.2	23.1	1,136	924	765	643	548	1,085	884	732	616	524
Kurdistan Region of Iraq	13.7	8.9	105	63	33	10	-7	97	56	26	4	-12
Total Undeveloped	**91.9**	**66.7**	**2,674**	**2,124**	**1,710**	**1,393**	**1,147**	**1,622**	**1,273**	**1,009**	**807**	**649**
Total Proved	**214.2**	**169.5**	**8,180**	**7,059**	**6,192**	**5,506**	**4,953**	**4,192**	**3,600**	**3,142**	**2,780**	**2,488**
Probable(5)												
Nigeria	190.2	155.0	10,418	7,874	6,062	4,743	3,764	3,491	2,606	1,973	1,513	1,171
Gabon	36.6	22.5	796	583	431	319	235	751	547	400	293	213
Kurdistan Region of Iraq	95.7	33.6	1,651	1,280	1,012	815	668	1,642	1,272	1,005	809	662
Total Probable	**322.5**	**211.1**	**12,865**	**9,737**	**7,505**	**5,877**	**4,666**	**5,884**	**4,424**	**3,379**	**2,615**	**2,046**
Total Proved plus Probable	**536.7**	**380.6**	**21,045**	**16,797**	**13,697**	**11,383**	**9,620**	**10,076**	**8,025**	**6,521**	**5,395**	**4,535**
Possible(6)												
Nigeria	134.9	103.2	8,103	6,210	4,866	3,890	3,164	2,243	1,734	1,377	1,119	929
Gabon	23.7	11.0	709	504	369	277	212	682	484	354	266	203
Kurdistan Region of Iraq	43.1	12.6	648	441	306	216	156	648	441	306	216	156
Total Possible	**201.7**	**126.8**	**9,461**	**7,155**	**5,541**	**4,383**	**3,532**	**3,573**	**2,659**	**2,037**	**1,601**	**1,288**
Total Proved plus Probable plus Possible	**738.4**	**507.4**	**30,505**	**23,952**	**19,238**	**15,766**	**13,152**	**13,649**	**10,684**	**8,558**	**6,996**	**5,822**

Notes:

(1) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(2) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(3) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(4) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(5) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(6) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(7) "Gross" means in respect of reserves and production, the total reserves and production attributable to Addax Petroleum's interest prior to the deduction of royalties and the relevant government's or government corporation's share of Profit Oil (which reserves are reported as "interest" in the Reserve Report) and "Net" means in respect of reserves and production, the total reserves and production attributable to Addax Petroleum's interest after deduction of Royalty Oil and the relevant government's or government corporation's share of Profit Oil.

(8) Columns may not add up due to rounding.

(9) Reserves presented exclude reserves in the Disputed Area of OML123 offshore Nigeria except for certain reserves attributable to existing producing wells in the Disputed Area which amount to proved reserves of 0.7 MMbbl. Reserves presented include reserves associated with partner carry on the Okwok field.

(10) The forecast prices and costs assumptions assume the continuance of current laws and regulations and changes in terminal selling prices, and take into account inflation with respect to future operating, capital and abandonment costs. In the Reserve Report, operating costs are assumed to escalate at 2 per cent per annum. Forecast crude oil prices as used by NSAI effective December 31, 2008, are as follows.

Year	Brent Crude	Antan Blend	Brass River Blend	Okwori Blend	OML137 Crude	Etame Crude	Rabi Blend	Remboué Crude	Taq Taq Crude
	($/bbl)	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*
2009	57.09	55.02	60.56	60.43	55.02	55.84	56.69	50.54	57.09
2010	69.99	67.92	73.46	73.33	67.92	68.74	69.59	63.44	69.99
2011	78.44	76.37	81.91	81.78	76.37	77.19	78.04	71.89	78.44
2012	87.96	85.89	91.43	91.30	85.89	86.71	87.56	81.41	87.96
2013	95.86	93.79	99.33	99.20	93.79	94.61	95.46	89.31	95.86
2014	97.26	95.19	100.73	100.60	95.19	96.01	96.86	90.71	97.26
2015	98.70	96.63	102.17	102.04	96.63	97.45	98.30	92.15	98.70
2016	100.15	98.08	103.62	103.49	98.08	98.90	99.75	93.60	100.15
2017	101.61	99.54	105.08	104.95	99.54	100.36	101.21	95.06	101.61
2018	103.15	101.08	106.62	106.49	101.08	101.90	102.75	96.60	103.15

and escalated at 2 per cent per annum thereafter.

(11) Included in the Reserve Report is a capital investment of $436.0 million to be expended from 2009 through 2012 to eliminate gas flaring in Nigerian PSCs by constructing infrastructure to supply all produced gas for sale or re-injection.

(12) Abandonment costs have been estimated for the end of the economic producing life of each property.

(13) The estimated Net Present Values of Future Net Revenues After Taxes include the effect of all deductions under the Production Sharing Contracts and Agreement including, in Nigeria, Royalty Oil, NNPC's share of Profit Oil, Tax Oil, NDDC levy, Education Tax and Tax Inversion Penalty, in Gabon, Royalty Oil, Government's share of Profit Oil, Domestic Market Obligation losses, Training Funds, Hydrocarbon Funds, Bonuses, and in the Kurdistan Region of Iraq, Royalty Oil, Training Funds, Hydrocarbon Funds, Bonuses, Domestic Market Obligation losses, NOC's share of Profit Oil and, as appropriate, the Government of Gabon's or the Kurdistan Regional Government's share of Profit Oil. The estimated Net Present Values of Future Net Revenues Before Taxes only include the effect of deducting Royalty Oil and government share of Profit Oil.

(14) Estimated Net Present Values of Future Net Revenue include the revenue effects of exploration expenditures of $122.7 million under the Nigerian PSCs but the costs of exploration activities are not deducted from future net revenue because they do not relate to the reserves being evaluated.

(15) For Gabon and the Kurdistan Region of Iraq, the estimates are after giving effect to the back-in rights held by relevant governments, government corporations or third parties.

Oil Reserves by Licence Area

The following tables set forth the oil reserves by licence area as at December 31, 2008.

Country/Asset	Gross Working Interest Proved	Gross Working Interest Proved plus Probable	Gross Working Interest Proved plus Probable plus Possible	Net Working Interest Proved	Net Working Interest Proved plus Probable	Net Working Interest Proved plus Probable plus Possible
	(MMbbl)	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Nigeria						
OML123	81.0	190.2	249.6	72.4	158.5	201.1
OML124	20.2	65.7	105.2	17.9	53.7	82.3
OML126	32.6	42.9	73.1	29.8	39.1	66.2
OML137	-	17.2	21.9	-	16.6	20.5
Okwok Field	-	7.9	9.1	-	7.2	8.2
subtotal - Nigeria	**133.8**	**324.0**	**458.9**	**120.1**	**275.1**	**378.3**
Gabon						
Awoun	12.6	17.4	19.6	7.7	10.4	11.6
Etame Marin	9.8	16.9	27.1	5.1	8.4	12.9
Maghena	24.9	29.0	31.8	14.8	17.8	19.1
Panthere NZE	17.9	33.9	41.3	11.8	22.4	25.9
Remboué	1.5	6.1	7.2	1.0	3.8	4.4
subtotal - Gabon	**66.7**	**103.3**	**127.0**	**40.5**	**63.0**	**74.0**
Kurdistan Region of Iraq						
Taq Taq(1)	13.7	109.5	152.6	8.9	42.5	55.0
Total	**214.2**	**536.7**	**738.4**	**169.5**	**380.6**	**507.4**

Totals may not add because of rounding

Notes:

(1) Reserves reported after giving effect of government back-in rights which Addax Petroleum expects to be exercised.

Additional Information Concerning Future Net Revenue

The following tables set forth the elements of future net revenue based on forecast prices and costs used by NSAI to determine total future net revenue.

Total Future Net Revenue (Undiscounted) as at December 31, 2008

	Revenue	Royalties(1)	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Taxes	Taxes(2)	Future Net Revenue After Taxes
				($million)				
Proved Reserves								
Nigeria	10,158	944	1,949	924	153	6,189	3,856	2,332
Gabon	5,449	2,142	1,024	322	75	1,886	124	1,762
Kurdistan Region of Iraq	1,008	359	227	282	35	105	8	97
Total	**16,616**	**3,445**	**3,199**	**1,528**	**263**	**8,180**	**3,988**	**4,192**
Proved Plus Probable								
Nigeria	27,487	4,078	3,278	3,313	212	16,606	10,783	5,823
Gabon	8,662	3,440	1,383	977	180	2,682	169	2,513
Kurdistan Region of Iraq	10,223	6,439	1,484	489	56	1,756	17	1,739
Total	**46,372**	**13,957**	**6,144**	**4,778**	**448**	**21,045**	**10,969**	**10,076**
Proved Plus Probable Plus Possible								
Nigeria	39,979	7,044	3,933	4,067	225	24,709	16,643	8,066
Gabon	10,911	4,662	1,552	1,121	184	3,392	197	3,195
Kurdistan Region of Iraq	14,574	9,595	1,943	572	60	2,404	17	2,388
Total	**65,465**	**21,301**	**7,429**	**5,760**	**469**	**30,505**	**16,857**	**13,649**

Totals may not add because of rounding.

Notes:

(1) Includes government share of Profit Oil, and carried interests, over-riding royalty interests and net profits interest payments where appropriate.

(2) Nigeria taxes include petroleum profit tax, education tax, Niger Delta Development Commission levy and tax inversion penalty. Gabon taxes include training fund, hydrocarbon fund, bonuses, and domestic market obligation losses. Kurdistan Region of Iraq taxes include production bonuses.

Total Future Net Revenue (Discounted at 10%) as at December 31, 2008

Country/Asset	Future Net Revenues Before Taxes[1]						Future Net Revenues After Taxes[2]					
	Proved		Proved plus Probable		Proved plus Probable plus Possible		Proved		Proved plus Probable		Proved plus Probable plus Possible	
	($mm)	*($/bbl)*	*($mm)*	*($/bbl)*	*($mm)*	*($/bbl)*	*($mm)*	*($/bbl)*	*($mm)*	*($/bbl)*	*($mm)*	*($/bbl)*
Nigeria												
OML123/124	3,451	38.23	8,352	39.36	11,554	40.77	1,302	12.87	2,726	10.65	3,564	10.05
OML126/137	1,354	45.43	2,167	38.91	3,781	43.60	538	16.52	879	14.62	1,394	14.68
Okwok Field	-	-	347	47.96	399	48.35	-	-	209	26.29	232	25.59
subtotal - Nigeria	**4,805**	**40.02**	**10,867**	**39.50**	**15,733**	**41.58**	**1,840**	**13.76**	**3,814**	**11.77**	**5,190**	**11.31**
Gabon												
Awoun	292	37.95	371	35.49	410	35.37	266	21.00	339	19.46	376	19.19
Etame Marine	196	38.27	335	39.69	499	38.57	188	19.29	323	19.07	483	17.80
Maghena	416	28.08	434	24.33	485	25.33	389	15.60	402	13.87	451	14.17
Panthere NZE	418	35.31	535	23.88	621	24.03	403	22.53	506	14.95	588	14.24
Remboué	32	31.22	111	28.82	139	31.27	30	20.32	106	17.42	133	18.44
subtotal - Gabon	**1,354**	**33.44**	**1,785**	**28.35**	**2,154**	**29.12**	**1,275**	**19.13**	**1,676**	**16.23**	**2,030**	**15.99**
Kurdistan Region of Iraq												
Taq Taq	33	3.65	1,045	24.60	1,351	24.55	26	1.92	1,032	9.43	1,338	8.77
Total	**6,192**	**36.53**	**13,697**	**35.99**	**19,238**	**37.92**	**3,142**	**14.67**	**6,521**	**12.15**	**8,558**	**11.59**

Totals may not add because of rounding

Notes:

(1) Calculated as the net present value of future net revenues before tax, discounted at 10 percent per annum and divided by net reserves.

(2) Calculated as the net present value of future net revenues after tax, discounted at 10 percent per annum and divided by gross reserves.

Reconciliation in Changes in Reserves

The following tables disclose changes between the reserves estimates made as at December 31, 2008 and the corresponding estimates made as at December 31, 2007.

Oil Reserves Reconciliation from December 31, 2007 to December 31, 2008

	NIGERIA			GABON			KURDISTAN REGION OF IRAQ			TOTAL		
Factors	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**
	(MMbbl)	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Gross												
December 31, 2007	**154.2**	**108.5**	**262.7**	**79.1**	**30.3**	**109.4**	**–**	**74.6**	**74.6**	**233.2**	**213.4**	**446.7**
Acquisitions	–	–	–	–	–	–	–	–	–	–	–	–
Discoveries	1.0	51.5	52.5	–	–	–	–	–	–	1.0	51.5	52.5
Dispositions	–	–	–	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	1.9	45.8	47.7	6.3	7.9	14.2	0.0	9.0	9.0	8.2	62.7	70.9
Technical Revisions	11.8	(12.2)	(0.4)	(13.1)	(1.3)	(14.4)	13.8	11.5	25.3	12.5	(2.0)	10.5
Economic Factors	4.5	(3.4)	1.1	4.6	(0.3)	4.3	–	0.7	0.7	9.1	(3.0)	6.1
Gross Production	(39.6)	–	(39.6)	(10.2)	–	(10.2)	(0.1)	–	(0.1)	(49.9)	–	(49.9)
December 31, 2008	**133.8**	**190.2**	**324.0**	**66.7**	**36.6**	**103.3**	**13.7**	**95.7**	**109.5**	**214.2**	**322.5**	**536.7**
Net												
December 31, 2007	**134.1**	**91.4**	**225.6**	**42.6**	**15.5**	**58.1**	**–**	**21.8**	**21.8**	**176.7**	**128.8**	**305.5**
Acquisitions	–	–	–	–	–	–	–	–	–	–	–	–
Discoveries	0.9	43.8	44.7	–	–	–	–	–	–	0.9	43.8	44.7
Dispositions	–	–	–	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	1.7	38.9	40.6	3.4	4.2	7.6	–	2.4	2.4	5.1	45.5	50.6
Technical Revisions	19.9	(17.9)	2.0	1.8	2.4	4.2	9.0	9.2	18.2	30.7	(6.3)	24.4
Economic Factors	1.2	(1.3)	(0.1)	1.8	0.4	2.2	–	0.2	0.2	3.0	(0.7)	2.3
Net Production	(37.7)	–	(37.7)	(9.1)	–	(9.1)	(0.1)	–	(0.1)	(46.9)	–	(46.9)
December 31, 2008[(1)]	**120.1**	**155.0**	**275.1**	**40.5**	**22.5**	**63.0**	**8.9**	**33.6**	**42.5**	**169.5**	**211.1**	**380.6**

Totals may not add because of rounding.

Additional Information Relating to Reserves Data

Future Development Costs

The following table sets forth development costs deducted by NSAI in the estimation of the future net revenue for the Corporation's properties and assets attributable to the reserve categories noted below.

Future Development Costs by Country as at December 31, 2008

Country	Total		2009		2010		2011		2012		2013	
	Discounted at		Discounted at		Discounted at		Discounted at		Discounted at		Discounted at	
	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%
						($million)						
Nigeria												
Proved	924	812	344	328	376	326	164	129	40	28	-	-
Proved plus Probable	3,313	2,802	712	679	1,052	912	1,427	1,124	119	85	2	2
Gabon												
Proved	322	277	102	97	118	102	59	47	39	28	4	2
Proved plus Probable	977	850	282	269	488	423	147	116	55	39	4	2
Kurdistan Region of Iraq												
Proved	282	241	62	59	110	96	108	85	2	2	-	-
Proved plus Probable	489	389	44	42	145	126	199	157	30	21	33	22
Total												
Proved	1,528	1,329	508	484	604	524	331	261	81	58	4	2
Proved plus Probable	4,778	4,041	1,038	990	1,686	1,461	1,773	1,397	204	146	39	26

Undeveloped Reserves

Addax Petroleum attributes proved undeveloped reserves in accordance with the CIM definitions. Undeveloped reserves are "those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned". The attribution of proved undeveloped reserves is based on flow test information obtained from various zones, the similarity of well log information relative to the producing zones, and production and pressure performance information. Proved undeveloped reserves are attributed based on field development plans as approved by the respective government agencies (NNPC or DGH) or as incorporated in the internal budget of Addax Petroleum for the next two years.

The following table sets out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for the Corporation's product type for each of the most recent two financial years. The Corporation's petroleum production consists solely of light and medium crude oil.

Forecast Prices and Costs	Proved Undeveloped		Probable Undeveloped	
	First Attributed Gross	Cumulative Gross	First Attributed Gross	Cumulative Gross
	(MMbbl)		*(MMbbl)*	
December 31, 2006	36.2	82.5	81.4	171.7
December 31, 2007	28.0	96.7	53.3	190.1
December 31, 2008	35.9	94.6	131.9	207.3

Production Estimates

The following table sets forth, by country, the volume of production estimated for the first year in estimating the Corporation's future net revenues based on forecast prices and costs.

Country	2009 Estimated Production Volume (Mbbl) (1)	
	Gross Proved	**Gross Probable**
Nigeria(2)	37,620	4,544
Gabon (3)	10,722	1,000
Iraq (4)	611	87

Notes:

(1) The Corporation's petroleum production consists solely of light and medium crude oil.

(2) The Nda field accounts for more than 20 per cent of the estimated 2009 production volume for gross proved reserves in Nigeria. The 2009 estimated production volume for Nda is 7.7 MMbbl for gross proved reserves. The Oron West / North Oron and Okwori fields each account for more than 20 per cent of the estimated 2009 production volume for gross probable reserves in Nigeria. The 2009 estimated production volume for Oron West / North Oron is 1.6 MMbbl and for Okwori is 1.3 MMbbl for gross probable reserves.

(3) The Tsiengui (Maghena) field accounts for more than 20 per cent of the estimated 2009 production volume for gross proved reserves in Gabon. The 2009 estimated production volume for Tsiengui (Maghena) is 5.1 MMbbl for gross proved reserves. The Obangue (Panthere NZE) field accounts for more than 20 per cent of the estimated 2009 production volume for gross probable reserves in Gabon. The 2009 estimated production volume for Obangue (Panthere NZE) is 0.6 MMbbl for gross probable reserves.

(4) The Taq Taq field accounts for more than 20 per cent of the estimated 2009 production volume for the Kurdistan Region of Iraq. The 2009 estimated production volume for Taq Taq field is 0.6 MMbbl for gross proved and 0.1 MMbbl for gross probable reserves.

Contingent Gas Resources

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets.

The contingent gas resources presented in this AIF are comprised of natural gas, LPG, and pentanes plus (C5+) components from the Corporation's Nigerian fields located in Okwok and OML123, OML124, OML126 and OML137. All of the contingent gas resources are located in fields in which wells have been drilled through the gas portion of the reservoirs to help define the gas pay thickness, reservoir quality, and areal extent. There are no gas sales from the properties since no gas market connection is available, nor does Addax Petroleum currently own the gas rights. Addax Petroleum is negotiating with the Nigerian Government for PSC gas rights and is investigating commercialization of produced gas through several markets. These markets include sales to other operators in the area, liquefied natural gas projects, gas-to-liquids projects, and gas cycling through LPG plants. If these issues are resolved, all or some portion of the contingent resources estimated may be reclassified as reserves. No economic evaluation has been performed on these resources at this time. All produced gas is presently flared, consumed for lease use, or reinjected into the oil reservoirs to maintain reservoir pressure. Contingent gas resources have not been estimated for the Gabon or Iraq concessions.

The following table sets forth the contingent gas resources estimated by NSAI assuming Addax Petroleum's working interest in the respective licence areas. **There is no certainty that these contingent resources will be commercially viable.**

Estimates of Contingent Gas Resources for Nigeria as at December 31, 2008

Licence Area	Estimate Category	Shrunk(1)	LPG(2)	C_5+(3)
		(Bcf)	*(MMbbl)*	*(MMbbl)*
OML 123	Low Estimate(4)	829.2	12.9	8.1
	Best Estimate(5)	1,013.0	15.5	9.7
	High Estimate(6)	1,177.0	17.6	10.9

Licence Area	Estimate Category	Shrunk[1]	LPG[2]	C_5+[3]
		(Bcf)	*(MMbbl)*	*(MMbbl)*
OML 124	Low Estimate	276.8	11.5	4.3
	Best Estimate	377.0	16.1	6.7
	High Estimate	410.4	17.5	7.3
OML 126	Low Estimate	74.1	–	1.2
	Best Estimate	91.7	–	1.5
	High Estimate	112.1	–	1.9
OML 137	Low Estimate	1,106.2	–	26.2
	Best Estimate	1,337.1	–	34.0
	High Estimate	1,555.2	–	42.0
Okwok	Low Estimate	–	–	–
	Best Estimate	1.7	–	–
	High Estimate	2.2	–	–
Total	**Low Estimate**	**2,286.3**	**24.4**	**39.9**
	Best Estimate	**2,820.4**	**31.6**	**52.0**
	High Estimate	**3,256.7**	**35.1**	**62.1**

Totals may not add because of rounding.

Notes:

(1) Volume after deductions for plant fuel and the extraction of LPG and C5+ components from the gross contingent resources gas.

(2) Volumes based on 75 percent plant recovery efficiency of non-associated gas reservoirs.

(3) Volumes based on 100 percent plant recovery efficiency of non-associated gas reservoirs.

(4) Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate.

(5) Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate.

(6) High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate.

Prospective Oil Resources

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

The prospective oil resources presented in this AIF are for crude oil only from the Addax Petroleum licence areas located in Nigeria, Cameroon, Gabon, and deep water areas of Nigeria and São Tomé and Príncipe. The Nigeria licence areas include OML123, OML124, OML126, and OML137. In Cameroon, Addax Petroleum has an interest in the Ngosso Concession. The Gabon concessions include the Awoun, Epaemeno, Etame Marin, Gryphon Marin, Ibekelia, Iris Marin, Kiarsseny, Maghena and Remboué Permits. In the Kurdistan Region of Iraq, Addax Petroleum has an interest in the Taq Taq and Sangaw North licence areas. The deep water areas include OPL291 in Nigeria and Blocks 1, 2, 3, and 4 of the JDZ, which encompasses territory jointly administered by Nigeria and São Tomé and Príncipe.

The prospective oil resources indicate exploration opportunities and development potential in the event a commercial discovery is made and should not be construed as reserves or contingent resources. A geologic risk assessment was performed for these properties. No economic evaluation has been performed on these resources at this time. Prospective gas resources associated with these properties have not been evaluated. The Addax Petroleum interests used to calculate prospective oil resources assume that all phases, and work programmes described in the licence operating agreements proceed as planned.

The following table sets forth the unrisked and risked prospective oil resources as estimated by NSAI attributable to Addax Petroleum's working interests in the respective licence areas. **There is no certainty that any portion of these prospective oil resources will be discovered. If discovered, there is no certainty that their development will be commercially viable.**

Probabilistic Estimates of Unrisked and Risked Prospective Oil Resources to Addax Petroleum Corporation Working Interest as at December 31, 2008

Region / Licence Area	Unrisked[1]			Risked[1]		
	Low Estimate[2][3]	Best Estimate[4]	High Estimate[2][5]	Low Estimate[2]	Best Estimate	High Estimate[2]
	(MMbbl)	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*	*(MMbbl)*
Nigeria						
OML123	189.1	340.5	505.9	37.1	71.4	103.8
OML124	85.3	110.4	136.5	7.8	9.3	13.4
OML126	138.6	271.8	429.7	26.3	50.5	78.2
OML137	150.7	253.5	359.3	68.6	112.0	155.9
Subtotal		976.2			243.1	
Cameroon						
Ngosso	36.5	53.8	73.3	7.9	12.3	17.1
Gabon						
Awoun	14.5	30.9	50.6	3.7	7.8	12.7
Epaemeno	15.1	27.8	40.7	2.3	4.2	6.1
Etame Marin	19.7	44.7	75.8	8.5	18.8	31.7
Gryphon Marin	26.9	52.3	79.1	4.1	8.4	12.9
Ibekelia	6.8	11.2	15.5	1.1	1.9	2.6
Iris Marin	5.6	10.2	14.6	0.8	1.5	2.1
Kiarsseny[3]	15.8	30.9	46.8	7.8	12.5	17.4
Maghena	17.3	36.3	56.4	2.5	5.2	8.1
Remboué[3]	1.8	3.7	5.8	0.3	0.7	1.0
Subtotal		248.0			60.9	
Kurdistan Region of Iraq						
Kewa Chirmila	4.2	9.7	16.1	0.4	1.0	1.7
Sangaw North	56.9	125.9	209.0	6.6	14.4	24.2
Subtotal		135.6			15.4	
Deep water						
JDZ Block 1	126.7	172.9	223.6	49.4	66.0	84.1
JDZ Block 2	26.4	50.1	77.7	12.7	24.9	39.2
JDZ Block 3	27.1	41.0	56.8	8.7	13.1	18.1
JDZ Block 4	344.6	528.7	729.0	133.9	201.8	274.5
OPL291	344.2	566.0	814.9	114.4	187.6	270.0
Subtotal		1,358.6			493.4	
Total		**2,772.2**			**825.1**	

Totals may not add because of rounding.

Notes:

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective licence area.

(2) It should be noted that the arithmetic sum of multiple probability distributions is correct only when summing the mean values. The arithmetic sum of the low estimates may be very conservative, and the arithmetic sum of the high estimates may be very optimistic. Statistical summation of multiple independent prospect entities results in narrowing the range between the low and high estimates toward the total sum of the means. Therefore, the only arithmetic sum presented in our tables of results is the sum of the means.

(3) These resources are reported after giving effect to government back-in rights, which Addax Petroleum Corporation expects to be exercised.

(4) For the low estimate resources, there is at least a 90 percent probability (P90) that the quantities of oil and gas actually recovered will equal or exceed the estimated amounts.

(5) The best estimate resources correspond to a measure of the central tendency of the uncertainty distribution, represented herein as the mean value.

(6) For the high estimate resources, there is at least a 10 percent probability (P10) that the quantities of oil and gas actually recovered will equal or exceed the estimated amounts.

Significant Factors or Uncertainties

Other than various risks and uncertainties that participants in the oil and gas industry are exposed to generally, the Corporation is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors" section.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table sets forth the number and status of wells as at December 31, 2008, which are producing or which the Corporation considers to be capable of production.

	Producing		Non-producing	
Property	**Gross**	**Net**	**Gross**	**Net**
OML123				
Adanga	17	17	16	16
Ebughu (and extensions)	18	18	10	10
Oron West and North Oron	16	16	5	5
Adanga North	2	2	—	—
Akam	—	—	10	10
Bogi	1	1	—	—
Mimbo	1	1	1	1
Ukpam	—	—	2	2
OML124				
Izombe	7	7	11	11
Ossu	12	12	4	4
OML126				
Okwori	8	8	2	2
Nda	3	3	1	1
Onshore Gabon				
Tsiengui	31	29	8	7
Obangue	5	5	3	3
Autour	—	—	—	—
Tsiengui West	5	2	—	—
Koula	—	—	3	1
Rembоué	6	6	4	4
Offshore Gabon				
Etame	4	1	1	—
Avouma South	2	1	—	—
Kurdistan Region of Iraq				
Taq Taq	—	—	10	5
Total	**139**	**129**	**91**	**82**

Addax Petroleum has three properties to which reserves have been attributed and which are capable of production, but which are not currently producing, namely Okwok and OML137 in Nigeria and the Taq Taq licence area in the Kurdistan Region of Iraq. The wells capable of production at Okwok were drilled in 2006 and are currently suspended for potential tie-back to production facilities. The wells capable of production in OML137 at Ofrima North were drilled in 2008. The wells capable of production in the Kurdistan Region of Iraq have been non-producing for periods from less than one year to approximately 40 years, and have not been producing in any material quantities due to a lack of suitable facilities and transportation infrastructure. The Corporation anticipates constructing such suitable transportation infrastructure as part of an overall field development plan. See "Business of the Corporation – Kurdistan Region of Iraq."

Drilling History

The following table summarizes the total number of exploration, appraisal and development wells (excluding placement wells and unplanned sidetracks) within the properties which the Corporation drilled during its 2008 financial year.

Addax Petroleum 2008 Drilling History Summary Table

Addax Petroleum 2008 Drilling History Summary Table

	Nigeria		Gabon		Cameroon		Kurdistan Region of Iraq	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development								
Oil producers	14	14	23	17	—	—	—	—
Water injectors	4	4	—	—	—	—	—	—
Gas Injectors	1	1	1	1	—	—	—	—
Total Development	19	19	24	18	—	—	—	—
Total Exploration	2	2	3	2	4	2	—	—
Total Appraisal	7	7	3	2	—	—	4	2
Total	**28**	**28**	**30**	**21**	**4**	**2**	**4**	**2**

Drilling Success

The following table summarizes the number of successful and unsuccessful exploration, appraisal and development wells which the Corporation drilled during its 2008 financial year.

Addax Petroleum 2008 Drilling Success Summary Table

Addax Petroleum 2008 Drilling Success Summary Table

	Nigeria		Gabon		Cameroon		Kurdistan Region of Iraq	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Successful	1	1	0	0	1	1	—	—
Unsuccessful	1	1	3	2	3	2	—	—
Appraisal								
Successful	7	7	2	1	—	—	4	2
Unsuccessful	0	0	1	1	—	—	—	—
Development								
Successful	19	19	23	17	—	—	—	—
Unsuccessful	0	0	1	1	—	—	—	—
Total								
Successful	**27**	**27**	**25**	**18**	**1**	**1**	**4**	**2**
Unsuccessful	**1**	**1**	**5**	**4**	**3**	**2**	—	—

2008 Capital Expenditures

The following table sets forth Addax Petroleum's capital expenditures for the most recently completed financial year.

2008 Capital Expenditures

	Year Ended December 31, 2008			
	Acquisitions	Development	Exploration & Appraisal	Total
	($ million)			
Nigeria				
OML123/124	—	719	33	752
OML126/137	—	277	61	338
Okwok	—	4	—	4
Other Nigeria	13	5	26	44
subtotal	**13**	**1,005**	**120**	**1,138**
Gabon				
Onshore, Producing	—	343	17	360
Offshore, Producing	—	28	7	35
Other, Non-producing	25	—	42	67
subtotal	**25**	**371**	**66**	**462**
Cameroon	**3**	**—**	**61**	**64**
Joint Development Zone	**—**	**—**	**21**	**21**
Kurdistan Reg. of Iraq				
Taq Taq	—	—	49	49
Sangaw North	30	—	7	37
subtotal	**30**	**—**	**56**	**86**
Other	**—**	**5**	**—**	**5**
TOTAL	**71**	**1,381**	**324**	**1,776**

Quarterly – Daily Production Volumes & Operating Netbacks

The following tables set forth Addax Petroleum's daily production volumes and operating netbacks for each quarter of its most recently completed financial year.

	Q4	Q3	Q2	Q1	Annual
Production (Mbbl/d)					
Nigeria	113.1	103.6	105.5	109.7	108.0
Gabon	29.4	27.7	27.4	29.4	28.5
Total	**142.5**	**131.3**	**132.9**	**139.1**	**136.5**
Operating Netbacks ($/bbl)					
Nigeria					
Realized Sales Price	49.01	110.86	124.86	97.02	94.53
Royalties	10.97	20.23	22.54	17.61	17.71
Operating expenses	6.86	7.26	9.01	7.43	7.61
Operating netback	**31.18**	**83.37**	**93.31**	**71.98**	**69.21**
Gabon					
Realized Sales Price	50.48	108.25	117.50	91.89	93.80
Royalties	17.78	17.96	22.33	6.44	16.35
Operating expenses	14.75	11.41	11.34	10.85	12.05
Operating netback	**17.95**	**78.88**	**83.83**	**74.60**	**65.40**
Total					
Realized Sales Price	49.28	110.32	123.17	96.03	94.38
Royalties	12.30	19.77	22.48	15.45	17.43
Operating expenses	8.40	8.12	9.55	8.09	8.53
Operating netback	**28.58**	**82.43**	**91.14**	**72.49**	**68.42**

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation does not expect to incur any abandonment or reclamation costs within the next three years.

DIVIDENDS

Addax Petroleum has historically declared quarterly cash dividends on the Common Shares. The payment and the amount of dividends declared in any fiscal quarter depends on Addax Petroleum's earnings, financial requirements and other conditions existing which Addax Petroleum's Board of Directors may consider relevant at such future time, including applicable restrictions arising under the Secured Revolving Debt Facility on the ability of APHL to pay dividends or other distributions to the Corporation.

Addax Petroleum paid its first quarterly dividend for the quarter ending June 30, 2006. All dividends paid by Addax Petroleum Corporation are eligible dividends unless indicated otherwise. All of the dividends paid by Addax Petroleum Corporation in 2006, 2007 and 2008 were eligible dividends under the *Income Tax Act* (Canada). The following table sets forth the dividends declared and paid by Addax Petroleum in each of 2006, 2007 and 2008:

2006 Dividends

Declaration Date	Record Date	Payment Date	Amount ($)
August 1, 2006	August 24, 2006	September 14, 2006	CAD 0.05
November 13, 2006	November 30, 2006	December 14, 2006	CAD 0.05

2007 Dividends

Declaration Date	Record Date	Payment Date	Amount ($)
February 20, 2007	March 1, 2007	March 15, 2007	CAD 0.05
May 8, 2007	May 31, 2007	June 14, 2007	CAD 0.05
August 3, 2007	August 30, 2007	September 13, 2007	CAD 0.05
November 12, 2007	November 30, 2007	December 14, 2007	CAD 0.05

2008 Dividends

Declaration Date	Record Date	Payment Date	Amount ($)
February 18, 2008	March 6, 2008	March 20, 2008	CAD 0.10
May 2, 2008	May 29, 2008	June 12, 2008	CAD 0.10
August 6, 2008	August 28, 2008	September 11, 2008	CAD 0.10
November 7, 2008	November 27, 2008	December 11, 2008	CAD 0.10

On March 3, 2009, the Corporation declared a dividend of CAD 0.10 per Common Share. The dividend is payable on April 2, 2009 to holders of Common Shares of record on March 19, 2009.

DESCRIPTION OF SHARE CAPITAL

Addax Petroleum is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series.

Common Shares

The holders of Common Shares will be entitled to receive notice of, and to exercise one vote per share at every meeting of shareholders of Addax Petroleum, to receive such dividends as the Board of Directors declares and to share equally in the assets of Addax Petroleum remaining upon the liquidation of Addax Petroleum after the creditors of Addax Petroleum have been satisfied, subject to the prior rights of the holders of Preferred Shares.

Preferred Shares

The Preferred Shares will be issuable in series, with each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors of Addax Petroleum prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of Addax Petroleum, whether voluntary of involuntary, the Preferred Shares are entitled to preferences over Addax Petroleum Common Shares and any other shares ranking junior to the Preferred Shares and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of each series.

MARKET FOR SECURITIES

Common Shares

Addax Petroleum's Common Shares were listed for trading on the TSX on February 16, 2006 and admitted to trading on the LSE on May 24, 2007. On both exchanges, the shares trade under the symbol "AXC". The high and low trading prices and the aggregate volume of trading of the Common Shares on the TSX and the LSE for 2008 are set forth below.

2008 Common Share Trading Price Range

	Toronto Stock Exchange			London Stock Exchange		
	High (CAD)	**Low (CAD)**	**Volume**	**High (GBP)**	**Low (GBP)**	**Volume**
January	43.95	35.00	8,417,451	22.28	17.71	391,086
February	45.58	40.15	8,172,396	23.28	19.98	216,258
March	45.50	37.65	8,464,245	23.23	18.70	407,561
April	46.65	40.01	8,090,079	23.40	19.75	258,992
May	54.34	43.50	10,388,325	27.44	21.81	325,002
June	55.21	46.21	8,885,088	27.80	23.21	281,852
July	51.13	38.55	10,745,745	25.31	18.75	871,122
August	42.45	35.15	10,162,737	21.30	17.65	428,299
September	39.48	27.92	13,528,986	20.61	14.75	715,129
October	30.46	13.20	22,044,598	15.74	7.50	525,806
November	22.00	12.13	17,421,471	10.52	6.07	103,074
December	21.50	14.26	10,744,704	11.70	7.55	718,074

Convertible Notes

Addax Petroleum's Convertible Notes were listed for trading on the London Stock Exchange Professional Securities Market on May 31, 2007. The following table sets forth the high and low closing prices of the Convertible Notes on the London Stock Exchange for 2008, as quoted on Bloomberg.

Convertible Notes Closing Price

2008	**High**	**Low**
January	113.63	104.96
February	115.99	109.65
March	115.17	100.43
April	110.09	102.46
May	123.48	107.58
June	122.51	112.57
July	115.38	101.02
August	102.16	95.65
September	98.43	79.13
October	78.11	45.04
November	62.44	46.78
December	63.92	59.51

DIRECTORS AND OFFICERS

The following table sets out the names and municipalities of residence of each of the current directors and officers of Addax Petroleum and their current positions and offices with Addax Petroleum and their principal occupations and positions held during the last five years.

Name and Municipality of Residence	Age	Position with the Corporation	Since	Principal Occupation and Principal Positions Held During the Last Five Years
Peter Dey(3)(5) *Toronto, Ontario*	68	Director, Chairman of the Board of Directors and Chairman of the Corporate Governance, Nominating and Compensation Committee	2005	Chairman of Paradigm Capital Inc., Director of Goldcorp Inc., Coventree Inc. and Redcorp Ventures Ltd.
Jean Claude Gandur *London, United Kingdom*	60	Director and President & Chief Executive Officer	2002(1)	Officer of Addax Petroleum. Chairman of the Advisory Board of The Addax and Oryx Group Ltd. and Non-Executive Chairman of AXMIN Inc. Formerly, Chief Executive Officer of The Addax and Oryx Group Ltd.
Brian Anderson(3)(4) *Kowloon, Hong Kong*	65	Director and Chairman of the Technical and Reserves Committee	2005	Chairman and Managing Director of Anderson Energy (Hong Kong) Limited, Chairman and Director of CleanCoalGas Ltd., and Acura Ltd. Formerly, Director of MPF Corp. Ltd.
James Davie(3)(5) *Toronto, Ontario*	65	Director	2005	Private Investor. Member of the Independent Review Committee for the Brompton Group of Funds, Director of Range Royalty Management Ltd., Member of the Advisory Board for KEP I and KEP II Funds.
Stephen Paul de Heinrich(3)(5) *Dully, Switzerland*	66	Director	2005	Independent Consultant, Associate with Beldi & Cie S.A. Formerly, Vice Chairman of Advisory Board of The Addax and Oryx Group Ltd.
Gerry Macey(4)(5) *Calgary, Alberta*	63	Director	2005	Director of Andora Energy Corp., Verenex Energy Inc. and PanOrient Energy Corp. Formerly, Executive Vice President and President, International New Ventures Exploration, Division of EnCana Corporation and Executive Vice President, Exploration, of PanCanadian Petroleum Corporation.
Afolabi Oladele(4) *Toronto, Ontario*	57	Director	2005	Partner, Oil and Gas, for Capital Alliance Nigeria, Chairman of Subsurface Assets Management Co. and Netco-Dietsmann Ltd., and Director of Freezone Fabrication International Oil & Gas Facilities Fabrication Co., DeltaAfrik, Sudelletra Nigeria Ltd., DWC Drilling Co. and The Addax and Oryx Group Ltd.
Wesley Twiss(3)(4) *Calgary, Alberta*	63	Director and Chairman of the Audit Committee	2005	Corporate Director. Director and Audit Committee Chair of the Canadian Oil Sands Trust, Keyera Facilities Income Fund and EPCOR.
James Pearce *Cologny, Switzerland*	60	Chief Operating Officer	2005	Officer of Addax Petroleum. Formerly, General Manager of Deep Water Operations for Chevron Nigeria Ltd. and Managing Director for Chevron Oil Congo.
Michael Ebsary *Geneva, Switzerland*	47	Chief Financial Officer	1999(2)	Officer of Addax Petroleum, Director of The Addax and Oryx Group Ltd. Formerly, Director of AXMIN Inc. and Carpathian Gold Inc.
David Codd *Geneva, Switzerland*	56	Chief Legal Officer and Corporate Secretary	2005	Officer of Addax Petroleum. Formerly, Chairman of Edco Oil & Gas Ltd.

Notes:

(1) Mr. Gandur has been an officer of APHL (formerly APNV) since 2002 and became a director and officer of Addax Petroleum in 2005.

(2) Mr. Ebsary has been an officer of APHL (formerly APNV) since 1999 and became an officer of Addax Petroleum in 2005.

(3) Member of the Audit Committee.

(4) Member of the Technical and Reserves Committee.

(5) Member of the Corporate Governance, Nominating and Compensation Committee.

The term of office of the directors of Addax Petroleum will expire at the next annual meeting of the shareholders to be held on June 25, 2009. As of the date of this AIF, the directors and executive officers of Addax Petroleum other than Jean Claude Gandur, as a group, beneficially owned, directly or indirectly, or exercised control or direction over a total of 952,847 Common Shares representing approximately 0.61 per cent of the Common Shares outstanding. As of the same date, Jean Claude Gandur beneficially owned, directly or indirectly 5,606,084 Common Shares representing approximately 3.58 per cent of the Common Shares outstanding, in addition to the Common Shares controlled through his indirect control of AOG Holdings BV which owns and controls 55,241,829 Common Shares (35.28 per cent of the Common Shares outstanding).

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation:

(a) is, as at the date of the AIF or has been, within the 10 years before the date of the AIF, a director or executive officer of any company (including the Corporation), that while that person was acting in that capacity,

- (i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or
- (ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or
- (iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder.

CONFLICTS OF INTEREST

There are potential conflicts of interest to which the directors and officers of Addax Petroleum will be subject in connection with the operations of Addax Petroleum. In particular, certain of the directors of Addax Petroleum are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Addax Petroleum or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Addax Petroleum. The CBCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the CBCA.

Afolabi Oladele has a consulting agreement with Addax Petroleum Development (Nigeria) Limited pursuant to which Mr. Oladele is paid a monthly fee of $12,500.

PROMOTERS

AOG may be considered to be a promoter of Addax Petroleum in that it took the initiative in founding the business of Addax Petroleum N.V. (now Addax Petroleum Holdings Limited) and incorporating and organizing Addax Petroleum. AOG carries on several different businesses worldwide with particular emphasis on Africa, including petroleum and refined products trading, oil storage, retail petroleum products and mining businesses. AOG was incorporated in 1987 and has established itself as one of the largest independent oil trading companies in Africa and the largest marine fuel supply company in West Africa.

During 2006 and subsequent to the IPO, AOG proposed a reorganization of AOG that gave shareholders the ability to exchange their AOG shares for Common Shares and other consideration. Certain shareholders of AOG elected to exchange their AOG shares in return for approximately 46.1 million Common Shares. As of the date of this AIF, the shareholders of AOG who elected to exchange their AOG shares for Common Shares have all received their Common Shares. In addition, in 2007 AOG entered into agreements with various shareholders whereby AOG exchanged approximately 8 million Common Shares of Addax Petroleum in return for redemption of AOG shares.

To the best of the knowledge of the directors and officers of Addax Petroleum, as of the date of this AIF, AOG Holdings BV owns and controls 55,241,829 Common Shares of Addax Petroleum representing approximately 35.28 per cent of the issued and outstanding Common Shares. AOG Holdings BV is an indirect wholly owned subsidiary of AOG in which Hydromel Ltd. has a majority holding. Hydromel Ltd. is wholly owned by Samsufi Trust, an overseas discretionary trust created by Jean Claude Gandur, the President and Chief Executive Officer of Addax Petroleum. Jean Claude Gandur is not a beneficiary of Samsufi Trust, however, he does have power of revocation over Samsufi Trust and can therefore be considered to have control directly over Samsufi Trust and indirectly over Hydromel Ltd., AOG and AOG Holdings BV.

LEGAL PROCEEDINGS

From time to time, Addax Petroleum may be subject to litigation arising out of its operations. As at the date of this AIF, Addax Petroleum is not a party to nor are any of its properties subject to any material legal proceedings nor are any such proceedings known by Addax Petroleum to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of Addax Petroleum or any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 per cent of the Common Shares and no associate or affiliate of any of the foregoing has, or has had, any material interest, direct or indirect, in any transaction prior to the date hereof or any proposed transaction that has materially affected or will materially affect Addax Petroleum or any of its affiliates, except as disclosed elsewhere in this AIF. See “Conflicts of Interest”.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of Addax Petroleum are Deloitte & Touche LLP, Chartered Accountants, 3000 Scotia Centre, 700 - 2nd Street SW, Calgary, Alberta, T2P 0S7. Deloitte & Touche LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Computershare Investor Services Inc. (“Computershare”), at its principal offices in Calgary, Alberta and Toronto, Ontario, is the registrar and transfer agent for Addax Petroleum’s Common Shares.

CORPORATE GOVERNANCE

Committees of the Board of Directors

Addax Petroleum recognizes the importance of adhering to excellent corporate governance standards. Addax Petroleum has developed comprehensive corporate governance policies and procedures, which will be assessed on a continuous basis, and has adopted a “best practices” approach to corporate governance. The Board of Directors has adopted the recommendations set out in National Policy 58-201 — *Corporate Governance Guidelines*. These include, among other things, creating an Audit Committee and a Corporate Governance, Nominating and Compensation Committee, each comprised solely of independent directors, and a Technical and Reserves Committee, comprised of a majority of independent board members, adopting board mandates and a code of business ethics and conduct as well as approving regular board performance assessments. The Board of Directors may, from time to time, establish additional committees.

The mandates of each of the three committees are set forth below.

Corporate Governance, Nominating and Compensation Committee

The Corporate Governance, Nominating and Compensation Committee assists the Board of Directors in fulfilling their responsibilities in relation to, among other things:

- the monitoring and oversight of the quality and effectiveness of the corporate governance practices and policies of the Corporation and its subsidiaries;
- considering nominees for the independent directors; and
- determining the adequacy and appropriateness of the compensation of officers and employees of the Corporation as well as the directors.

Technical and Reserves Committee

The Technical and Reserves Committee assists the Board of Directors in fulfilling their responsibilities in relation to, among other things:

- the independent engineering evaluation of the petroleum reserves of the Corporation and its subsidiaries, managing the relationship with the independent engineer and meeting with the independent engineer as required;
- the public disclosure and filings relating to the Corporation's petroleum reserves and operations;
- the appointment of the independent engineer and, together with management, defining the scope and supervising the methodology of the independent engineer's evaluation; and
- the monitoring of the operational performance of the Corporation.

Audit Committee

The Audit Committee assists the Board of Directors in fulfilling their responsibilities of oversight and supervision of, among other things:

- the audit of the consolidated financial statements of the Corporation, managing the relationship with the Corporation's auditors and meeting with the auditors as required in connection with the audit services provided by the Corporation's auditors;
- the Corporation's preparation and reporting of its annual and quarterly consolidated financial statements and management's discussion and analysis;
- the accounting and financial reporting practices and procedures of the Corporation and its subsidiaries;
- the activities and audits conducted by the Corporation’s internal auditor, including incident management reporting;
- the adequacy of internal controls and accounting procedures of the Corporation and its subsidiaries; and
- the quality and integrity of consolidated financial statements of the Corporation.

The Corporation’s Audit Committee consists of five independent directors, Messrs. Twiss, Dey, Anderson, Davie and de Heinrich, all of whom are considered to be “financially literate”, as defined by Multilateral Instrument 52-110 *Audit Committees* and the Audit Committee’s Charter. The education and experience of each member of the Corporation’s Audit Committee relevant to the performance of his responsibilities are as set forth below.

Wesley Twiss, Chairman

Mr. Twiss is a corporate director with over 40 years of energy industry experience, including 13 years as the senior financial officer of two major Canadian companies. He was Executive Vice President and Chief Financial Officer of PanCanadian Energy Corporation from October 2000 until April 2002 and was Executive Vice President and Chief Financial Officer of Petro-Canada from 1998 through 2000. In those roles, Mr. Twiss was responsible for directing all aspects of corporate financial affairs, as well as strategic management and corporate development. He is a Director and Audit Committee Chair of Canadian Oil Sands Trust, Keyera Facilities Income Fund and EPCOR. Mr. Twiss holds a Bachelor of Applied Science in Chemical Engineering from the University of Toronto and a Master of Business Administration from the University of Western Ontario. Mr. Twiss is a graduate of the Directors Education Program, Corporate Governance College of the Institute of Corporate Directors and holds the ICD.D designation.

Peter Dey

Mr. Dey is the Chairman of Paradigm Capital Inc. and a former partner of Osler, Hoskin & Harcourt LLP, a law firm specializing in corporate and securities law. From 1994 to 2001, he was Chairman of Morgan Stanley Canada Limited where he was responsible for the overall strategic direction of Morgan Stanley in Canada. Mr. Dey previously chaired The Toronto Stock Exchange Committee on Corporate Governance in Canada which released a report entitled “*Where Were the Directors?*” in 1994. From 1983 to 1985, Mr. Dey was the Chairman of the Ontario Securities Commission. Mr. Dey is the chairman of the Private Sector Advisory Group of the Global Corporate Governance Forum established by the World Bank and the Organization for Economic Co-operation and Development (“OECD”). He has a Bachelor of Science from Queen's University, a Bachelor of Laws degree from Dalhousie University and a Master of Laws degree from Harvard University. Mr. Dey is also a director of Goldcorp Inc., Coventree Inc. and Redcorp Ventures Ltd.

Brian Anderson

Before retiring in 2000, Mr. Anderson had a 34-year professional career, largely in the Royal Dutch/Shell Group of Companies. Mr. Anderson was appointed Managing Director of the Shell Petroleum Development Company and Chairman of Shell Nigeria in January 1994. His last assignment before retirement was three years based in Beijing as Chairman of the Shell Companies in North East Asia, principally involved in China and Hong Kong, but he also had overall responsibility for Shell's interests in Korea and Taiwan. Mr. Anderson is currently Chairman and Managing Director of Anderson Energy (Hong Kong) Limited, a consulting company which he set up in 2000 to specialize in assisting companies mostly in Africa and China in the energy sector. Mr. Anderson is also the Chairman and a Director of CleanCoalGas Ltd., and Chairman and a Director of Acura Ltd. He was formerly a Director of MPF Corp. Ltd. Mr. Anderson was born in Nigeria and is a citizen of the United Kingdom and studied Metaliferous Mining Engineering at Cambourne in the United Kingdom followed by an MSc in Petroleum Reservoir Engineering at London University.

James Davie

Mr. Davie has over 29 years of investment banking experience with RBC Dominion Securities Inc. before retiring in 2002. Mr. Davie held a number of senior positions at RBC Dominion Securities Inc. including Managing Director of Investment Banking and Head of Equity Capital Markets from 1987 to 1999. Mr. Davie has a Bachelor of Commerce degree from the University of Toronto and a Master of Business Administration from Queen's University. Mr. Davie is also a director of Range Royalty Management Ltd., a member of the Independent Review Committee for the Brompton Group of Funds, and a member of the Advisory Board for KEP I and KEP II Funds.

Stephen Paul de Heinrich

Mr. de Heinrich has more than 30 years experience in trading and investment in Africa. He has been instrumental in organizing counter trading export pre-financing and syndicated financial transactions in several African countries. Mr. de Heinrich is now an independent consultant as well as an associate with Beldi & Cie S.A., a Geneva-based corporate finance house. He was a non-executive director of AOG from 1988 to 1991 and was the Vice Chairman of its Advisory Board. He has been chairman and a director of SAMAX Resources Limited and Carpathian Gold Limited, among other companies. Mr. de Heinrich is a citizen of both Canada and Hungary and has a degree in economics from McMaster University, Hamilton, Canada.

The text of the Audit Committee Charter is attached to this AIF as Schedule “C”.

External Auditor Service Fees

The following summarizes the total fees billed by Deloitte & Touche LLP, the external auditor of the Corporation, in each of the years ended December 31, 2006, December 31, 2007 and December 31, 2008.

Audit Fees	
2006	$658,133
2007	$1,651,235
2008	$1,248,437

Audit fees billed in 2007 included amounts related to services performed in 2006.

Audit-Related Fees	
2006	$116,258
2007	$616,246
2008	$302,735

Audit-related fees in 2006 were primarily for accounting system reviews and review of equity offering prospectuses. In 2007, fees were primarily for time writing system reviews and UK listings of Common Shares and Convertible Notes. In 2008, fees were primarily for time writing system reviews, the audit of Addax Petroleum’s UK subsidiary and Addax Petroleum Mauritius Limited, translation costs and discussions about the conversion from Canadian GAAP to IFRS..

Tax Fees	
2006	$369,139
2007	–
2008	–

Tax fees billed in 2006 were primarily for tax planning assistance.

All Other Fees	
2006	$3,183
2007	–
2008	–

All other fees billed in 2006 were primarily for assistance in opening a new branch office and due diligence procedures for the IPO.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, the following are Addax Petroleum's material contracts entered into within the most recently completed financial year or, if before, which are still in effect:

Non-Competition Agreement

On February 8, 2006, the Corporation and AOG entered into the Non-Competition Agreement under which AOG agreed with Addax Petroleum that, provided AOG and Jean Claude Gandur together own not less than 25 per cent of the issued and outstanding Common Shares, neither AOG nor any of its subsidiaries will:

- acquire any petroleum properties or facilities or participate in the exploration for or development and production of petroleum or participate in any upstream petroleum business opportunities, unless AOG has first offered such business opportunities to Addax Petroleum and Addax Petroleum has declined to acquire such business opportunities. Such offer must remain open for acceptance for a minimum of 30 business days. For purposes of certainty, petroleum trading, downstream activities or non-petroleum resource activities of AOG shall not be considered directly competing interests; or
- participate in any person, other than acquiring not more than five per cent of the equity of a publicly listed company, which engages in the above prescribed activities.

Secured Revolving Debt Facility

On January 22, 2007, the Corporation entered into a 5 year, $1.5 billion senior secured reducing revolving debt facility arranged by BNP Paribas, Natixis and Standard Chartered Bank. The facility consisted of a $1.2 billion loan tranche and a $300 million letter of credit tranche. On April 30, 2007, the facility size was increased to $1.6 billion, with the long-term loan portion of the facility increasing to $1.3 billion. The letter of credit facility remained unchanged. The loan tranche of the facility has been used to re-finance the former bridge facility, as well as to fund budgeted capital expenditures, property acquisitions and for general corporate purposes, and is expected to be used for the same purposes in the future. The

facility is in the form of a borrowing base loan, is subject to potential reductions after three years and is secured against a portion of the Corporation's business interests.

Convertible Notes

On May 10, 2007, the Corporation announced a private placement in denominations of $200,000 of $300 million in principal amount of Convertible Notes. The principal amount included a $25 million overallotment option granted to the lead underwriters of the offering, Citigroup Global Markets Limited and UBS Limited. The Notes are constituted by a trust deed dated May 30, 2007 between Addax Petroleum and The Law Debenture Trust Corporation p.l.c. as Trustee.

The Notes are convertible into fully paid, non-assessable Common Shares of no par value in the share capital of Addax Petroleum and have a fixed annual coupon of 3.75 per cent and an initial conversion price of CAD 56.0612 per share (converted into United States dollars at a fixed rate of $1 = CAD 1.108), representing a premium of 49 percent to the United States dollar equivalent of the Corporation's volume-weighted average share price during the marketing period of the Notes. The Notes were issued at 100 per cent of their principal amount, and unless previously redeemed, converted or purchased and cancelled, they will mature in 2012. After three years and 21 days, the Notes will be callable at the option of the Corporation, so long as the Corporation's share price is at least 130 per cent of the conversion price.

Addax Petroleum has the option to reduce the dilutive effect of the Notes by way of a net share settlement option, allowing the Corporation to settle investor conversions by repaying the par value of the Notes in cash, and delivering only the difference between the value of the underlying shares and the par value in shares. The Notes were offered outside of Canada, including the United Kingdom and the United States, and were offered in Ontario and Quebec to accredited investors only. The private placement closed on May 30, 2007, and the Notes were admitted to the Official List of the UKLA and to trading on the Professional Securities Market of the London Stock Exchange on May 31, 2007.

Unsecured Revolving Debt Facility

On April 25, 2008 the Corporation entered into a two-year, $450 million senior unsecured revolving debt facility arranged by Calyon, BNP Paribas, and Standard Chartered Bank. The facility was subsequently increased to $500 million following syndication. In 2008, the facility was used to fund budgeted capital expenditures, property acquisitions and for general corporate purposes, as well as to cover short-term liquidity needs. The Corporation expects to continue using the unsecured facility for the same purposes.

INTERESTS OF EXPERTS

Netherland, Sewell & Associates, Inc. has certified a report with respect to NI 51-101 oil and gas reserves. As of the date hereof, neither NSAI nor any of the "designated professionals" of NSAI (as such terms is defined in Form 51-102F2) directly or indirectly, hold, have received or will receive any registered or beneficial interests in any of the Common Shares or other property of the Corporation or of any of the Corporation's associates or affiliates. In addition, none of such persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies is or is expected to be elected, appointed or employed as a director, officer or employee of Addax Petroleum or any associate or affiliate of Addax Petroleum.

ADDITIONAL INFORMATION

Additional information relating to the Corporation is available on the Corporation's website at www.addaxpetroleum.com and on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com. Filings made with the UK Financial Services Authority and the London Stock Exchange can be accessed through the Exchange's website, at www.londonstockexchange.com. Additional financial information is provided in the Corporation's annual financial statements and related annual management's discussion and analysis for the year ended December 31, 2008. Additional information about directors' and officers' remuneration and indebtedness will be contained in the Corporation's forthcoming management proxy circular, which will be available at www.sedar.com.

SCHEDULE "A"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR FORM 51-101F2

To the Board of Directors of Addax Petroleum Corporation:

1. We have evaluated Addax Petroleum Corporation's (the "**Corporation**") reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us as at December 31, 2008 and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management/Board of Directors:

Oil Reserves and Future Net Revenues (Forecast Prices and Costs) as at December 31, 2008

	Crude Oil Reserves		Estimated Net Present Values of Future Net Revenue Before Taxes Discounted at					Estimated Net Present Values of Future Net Revenue After Taxes Discounted at				
	Gross	Net	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(MMbbl)		($million)					($million)				
Proved												
Developed Producing	102.0	87.4	4,510	4,113	3,788	3,517	3,288	2,091	1,928	1,793	1,679	1,582
Developed Non-Producing	20.3	15.4	995	823	694	595	518	478	399	340	294	258
Undeveloped	91.9	66.7	2,674	2,124	1,710	1,393	1,147	1,622	1,273	1,009	807	649
Total Proved	**214.2**	**169.5**	**8,180**	**7,059**	**6,192**	**5,506**	**4,953**	**4,192**	**3,600**	**3,142**	**2,780**	**2,488**
Probable	322.5	211.1	12,865	9,737	7,505	5,877	4,666	5,884	4,424	3,379	2,615	2,046
Total Proved plus Probable	**536.7**	**380.5**	**21,045**	**16,797**	**13,697**	**11,383**	**9,620**	**10,076**	**8,025**	**6,521**	**5,395**	**4,535**
Possible	201.7	126.8	9,461	7,155	5,541	4,383	3,532	3,573	2,659	2,037	1,601	1,288
Total Proved plus Probable plus Possible	**738.4**	**507.4**	**30,505**	**23,952**	**19,238**	**15,766**	**13,152**	**13,649**	**10,684**	**8,558**	**6,996**	**5,822**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above.

NETHERLAND, SEWELL & ASSOCIATES, INC.
4500 Thanksgiving Tower
1601 Elm Street
Dallas, Texas
75201-4754

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: (Signed)
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dated: February 3, 2009

SCHEDULE "B"

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION FORM 51-101F3

Management of Addax Petroleum Corporation (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(Signed) JEAN CLAUDE GANDUR Chief Executive Officer	(Signed) MICHAEL EBSARY Chief Financial Officer
(Signed) BRIAN ANDERSON Director	(Signed) GERRY MACEY Director

Dated: March 3, 2009

SCHEDULE "C"

CHARTER OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS OF ADDAX PETROLEUM CORPORATION

Mission Statement

The Board of Directors (the "Board") of Addax Petroleum Corporation (the "Company") will establish an Audit committee (the "Committee") to assist the Board in fulfilling its obligations by overseeing and monitoring the Company's financial accounting and reporting process, its internal control over financial reporting and the external financial audit process.

Composition

The Committee shall consist of as many members as the Board shall determine from time to time but in any event, not fewer than three members of the Board. The initial members of the Committee shall be Wesley Twiss, Peter Dey, Brian Anderson, James Davie and Stephen de Heinrich. Each member of the Committee shall continue to be a member until a successor is appointed, unless the member resigns, is removed or ceases to be a member of the Board. The Board may fill a vacancy in the Committee at any time.

Members of the Committee shall be selected based upon the following and in accordance with applicable laws, rules and regulations. Each member shall be independent in accordance with applicable legal and regulatory requirements and in such regard shall have no direct or indirect material relationship with the Company which could, in the view of the Board, reasonably interfere with the exercise of a member's independent judgment. In addition, each member shall be financially literate or must become financially literate within a reasonable period of time after his or her appointment to the Committee. For these purposes, an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

Chair and Secretary

The Chair of the Committee shall be designated by the Board. The initial Chair of the Committee shall be Wesley Twiss. If the Chair is not present at a meeting of the Committee, the members of the Committee may designate an interim Chair for the meeting by majority vote of the members present. The general counsel of the Company shall be the Secretary of the Committee meetings, provided that if the Secretary is not present, the Chair of the meeting may appoint a secretary for the meeting with the consent of the Committee members who are present.

Meetings

The Chair of the Committee, in consultation with the Committee members, shall determine the schedule and frequency of the Committee meetings provided that the Committee will meet at least four times in each fiscal year and at least once in every fiscal quarter. The Committee shall have the authority to convene additional meetings as circumstances require.

Notice of meetings shall be given to each member not less than five business days before the time of the meeting, provided that meetings of the Committee may be held without formal notice if all of the members of the Committee are present and do not object to notice not having been given, or if those absent waive notice in any manner before or after the meeting. Notice of meeting may be given verbally or delivered personally, given by mail, facsimile or other electronic means of communication and need not be accompanied by an agenda or any other material. The notice shall however specify the purpose or purposes for which the meeting is being held.

Notice of every meeting shall be given to the external and, if applicable, internal auditors of the Company, and meetings shall be convened whenever requested by the external auditors or any member of the Committee in accordance with applicable law. The Committee shall meet separately and periodically with management, legal counsel and the external auditors. The Committee shall meet separately with the external auditors at every meeting of the Committee at which external auditors are present.

Decisions or recommendations of the Committee shall be evidenced by resolutions passed at meetings of the Committee and recorded in the minutes of such meetings or by an instrument in writing signed by all members of the Committee. A copy of the draft minutes of each meeting of the Committee and any written resolutions evidencing decisions or recommendations of the Committee shall be transmitted promptly by the Secretary to each member for adoption at the next meeting. The Committee shall report to the Board at each regularly scheduled Board meeting next succeeding any Committee meeting or the signing of any written resolution evidencing a decision or recommendation of the Committee.

A majority of the members of the Committee shall constitute a quorum.

Any matter that the Committee does not unanimously approve will be referred to the Board for consideration.

Meeting Agendas

Where possible, agendas for meetings of the Committee shall be developed by the Chair of the Committee in consultation with management and the Secretary, and shall be circulated to Committee members as far in advance of each Committee meeting as is reasonable.

Resources and Authority

The Committee shall have the resources and the authority to discharge its responsibilities, including the authority, in its sole discretion, to engage, at the expense of the Company, outside consultants, independent legal counsel and other advisors and experts as it determines necessary to carry out its duties, without seeking approval of the Board or management of the Company.

The Committee shall have the authority to conduct any investigation necessary and appropriate to fulfilling its responsibilities, and has direct access to and the authority to communicate directly with the internal and external auditors, the general counsel of the Company and other officers and employees of the Company.

The members of the Committee shall have the right for the purpose of performing their duties to inspect all the books and records of the Company and any subsidiaries and to discuss such accounts and records and any matters relating to the financial position, risk management and internal controls of the Company with the officers and external and internal auditors of the Company and any subsidiaries. Any member of the Committee may require the external or internal auditors to attend any or every meeting of the Committee.

Responsibilities

The Company's management is responsible for preparing the Company's financial statements and the external auditors are responsible for auditing those financial statements. The Committee is responsible for overseeing the conduct of those activities by the Company's management and external auditors, and overseeing the activities of the internal auditors.

The specific responsibilities of the Committee shall include those listed below. The enumerated responsibilities are not meant to restrict the Committee from examining any matters related to its purpose.

1. Financial Reporting Process and Financial Statements

The Committee shall:

(a) in consultation with the external auditors and the internal auditors, review the integrity of the Company's financial reporting process both internal and external, and any major issues as to the adequacy of the internal controls and any special audit steps adopted in light of material control deficiencies;

(b) review all material transactions and material contracts entered into between or amongst (i) the Company or any subsidiary of the Company, and (ii) any subsidiary, director, officer, insider or related party of the Company, other than officer or employee compensation arrangements approved or recommended by the Remuneration Committee of the Board, or transactions in the ordinary course of business;

(c) review and discuss with management and the external auditors: (i) the preparation of Company's annual audited consolidated financial statements and its interim unaudited consolidated financial statements, as well as the Company’s annual and interim Management Discussion & Analysis (MD&A); (ii) whether the financial statements present fairly (in accordance with generally accepted accounting principles) in all material respects the financial condition, results of operations and cash flows of the Company as of and for the periods presented; (iii) any matters required to be discussed with the external auditors according to generally accepted auditing standards; and (iv) an annual report by the external auditors describing: (A) all critical accounting policies and practices used by the Company; (B) all material alternative accounting treatments of financial information within generally accepted accounting principles that have been discussed with management of the Company, including the ramifications of the use such alternative treatments and disclosures and the treatment preferred by the external auditors; and (C) other material written communications between the external auditors and management;

(d) following completion of the annual audit, review with each of: (i) management; (ii) the external auditors; and (iii) the internal auditors, any significant issues, concerns or difficulties encountered during the course of the audit;

(e) review the annual financial statements and reports (including annual MD&A) of the Company and any other documents including press releases containing financial information of the Company that is likely to be material and recommend approval thereof to the Board prior to the submission of such documents to the applicable securities regulatory authorities;

(f) review the interim financial statements and reports (including interim MD&A) of the Company and recommend approval thereof to the Board prior to the submission of such documents to the applicable securities regulatory authorities;

(g) resolve disagreements between management and the external auditors regarding financial reporting; and

(h) review disclosure procedures with the Disclosure Committee established in accordance with the Company's Disclosure Policy, and be satisfied that adequate procedures are in place for the review of the public disclosure of financial information by the Company extracted or derived from the Company's financial statements, other than the disclosure referred to in the preceding paragraph, and periodically assess the adequacy of those procedures.

2. External Auditors

The Committee shall:

(a) require the external auditors to report directly to the Committee;

(b) be directly responsible for the selection, nomination, compensation, retention, termination and oversight of the work of the Company's external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and in such regard recommend to the Board the external auditors to be nominated for approval by the shareholders;

(c) approve all audit engagements and pre-approve the provision by the external auditors of all non-audit services, including fees and terms for all audit engagements and non-audit engagements, and in such regard the Committee may establish the types of non-audit services the external auditors shall be prohibited from providing and shall establish the types of audit, audit related and non-audit services for which the Committee will retain the external auditors. The Committee may delegate to one or more of its members the authority to pre-approve non-audit services, provided that any such delegated pre-approval shall be exercised in accordance with the types of particular non audit services authorized by the Committee to be provided by the external auditor and the exercise of such delegated pre-approvals shall be presented to the full Committee at its next scheduled meeting following such pre-approval;

(d) review and approve the Company's policies for the hiring of partners and employees and former partners and employees of the external auditors;

(e) consider, assess and report to the Board with regard to the independence and performance of the external auditors; and

(f) request and review the audit plan of the external auditors as well as a report by the external auditors to be submitted at least annually regarding: (i) the internal quality-control procedures; and (ii) any material issues raised by the external auditor's own most recent internal quality-control review or peer review of the auditing firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues.

3. Accounting Systems and Internal Controls

The Committee shall:

(a) oversee management's design and implementation of and reporting on internal controls. The Committee shall also receive and review reports from management, the internal auditors and the external auditors on an annual basis with regard to the reliability and effective operation of the Company's accounting system and internal controls; and

(b) review quarterly and annually the activities, organization and qualifications of the internal auditors and discuss with the external auditors the responsibilities, budget and staffing of the internal audit function.

4. Legal and Regulatory Requirements

The Committee shall:

(a) review timely analysis by the Disclosure Committee of significant issues relating to public disclosure and reporting;

(b) review, prior to finalization, periodic public disclosure documents containing financial information, including the annual and interim financial statements, annual information form and MD&A and press releases and recommend approval of the foregoing to the Board prior to their disclosure or filing;

(c) prepare the report of the Committee required to be included in the Company's periodic filings;

(d) review with the Company's internal counsel legal compliance matters, significant litigation and other legal matters that could have a significant impact on the Company's financial statements; and

(e) assist the Board in the oversight of compliance with legal and regulatory requirements and review with internal legal counsel the adequacy and effectiveness of the Company's procedures to ensure compliance with legal and regulatory responsibilities.

5. Additional Responsibilities

The Committee shall:

(a) discuss policies with the external auditor, internal auditor and management with respect to risk assessment and risk management;

(b) establish procedures and policies for (i) the receipt, retention, treatment and resolution of complaints received by the Company regarding accounting, internal accounting controls or auditing matters; and (ii) the confidential, anonymous submission by directors or employees of the Company of concerns regarding questionable accounting or auditing matters or any potential violations of legal or regulatory provisions;

(c) prepare and review with the Board an annual performance evaluation of the Committee;

(d) report regularly to the Board, including with regard to matters such as the quality or integrity of the Company's financial statements, compliance with legal or regulatory requirements, the performance of the internal audit function, and the performance and independence of the external auditors. Minutes of each meeting of the Committee shall be recorded and maintained and provided to the Board as soon as possible following the meeting; and

(e) review and reassess the adequacy of the Committee's Charter on an annual basis (but no alteration to the Committee's charter and the responsibilities of the Committee shall be effective without the approval of the Board).

6. Limitation on the Oversight Role of the Committee

Nothing in this Charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all members of the Board are subject.

Each member of the Committee shall be entitled, to the fullest extent permitted by law, to rely on the integrity of those persons and organizations within and outside the Company from whom he or she receives financial and other information, and the accuracy of the information provided to the Company by such persons or organizations.

While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate and in accordance with generally accepted accounting principles in Canada and applicable rules and regulations. These are the responsibility of management and the external auditors.