Gaffney, Cline & Associates

RESERVE STATEMENT FOR THE MANATI FIELD, BRAZIL AS OF DECEMBER 31, 2011

PREPARED FOR

Queiroz Galvão Exploração e Produção S.A.

AUGUST 2012

Gaffney, Cline & Associates

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AR-12-2000.00 /CG/RW/LT2096

August 7, 2012

Mr. Danilo Oliveira
Diretor de Operações e Produção
Queiroz Galvão Exploração e Produção S.A.
Av. Almirante Barroso 52, Sala 1301
Rio de Janeiro, RJ, Brasil

Reserves Statement for the Manati Field, Brazil
as of December 31, 2011

Dear Mr. Oliveira:

This reserve statement have been prepared by Gaffney, Cline & Associates (GCA) at the request of Queiroz Galvão Exploração e Produção S.A. (QGEP), a non-operator of and participant with 45% interest in the *Manati Field of the Camamu-Almada Basin, Offshore Brazil.* GCA has updated its audits of Manati as of December 31, 2009 and 2010 to an effective date of December 31, 2011. On the basis of pertinent technical and other information made available to us concerning this property unit, we hereby provide the reserve statement given in the table below.

Hydrocarbon Reserves Statement as of December 31, 2011

Manati Field, Camamu-Almada Basin, Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

	Gross (100%) Field Volumes				Reserves Net to QGEP's Interest			
	Condensate		Natural Gas		Condensate		Natural Gas	
	(MMBbl)	(Mm^3)	(Bcf)	(Bm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bm^3)
1P	**1.8**	**288**	**697**	**19.7**	**0.8**	**129**	**314**	**8.9**
2P	1.9	298	724	20.5	0.8	134	326	9.2
3P	2.0	318	777	22.0	0.9	143	350	9.9

Hydrocarbon liquid volumes represent condensate to be recovered during field separation and are reported in millions of stock tank barrels and thousands of cubic meters. Natural gas volumes represent expected gas sales, and are reported in billions (10^9) of cubic feet and in billions of cubic meters (at standard conditions of 14.7 psia and 68 degrees Fahrenheit). The volumes have been reduced for fuel usage in the field. Article 47 of the Brazilian Petroleum Law states that "…royalties are to be paid on a monthly basis, in national currency …" and therefore royalties are treated as cash deductions rather than a reduction to volumes.

Gas reserves sales volumes are based on a firm, existing gas contract and on the reasonable expectation that the amendment to such gas sales contract on similar terms will be approved in the near future adding 5.6 Bm^3 to the 1P case.

The original sales contract signed in 2007 specified a daily contract quantity (DCQ) rate of 6 million cubic meters per day through 2011 followed by a reduced DCQ of 4 million cubic meters per day through 2016. The total contractual sales volume was 23 Bm^3. As of the end of 2010, the partners had negotiated an amendment to this contract that was anticipated to receive formal approval in 2011. This amendment specifies a rate of six million cubic meters per day through the end of 2016, which requires surface gas compression, and a total volume limited only by the estimated total recovery from the field.

At the “as of date” of this audit this amendment has not been signed by the operator. QGEP considers this delay a minor issue as all partners are continuing with the necessary activity to incorporate surface gas compression. Considering that the main investments for late compression will be done in the 2012/2013 period, GCA considers that the final signatures and approvals are still reasonably certain to be obtained. However GCA considers that if at the end of 2012 the amendment remains unsigned, then its approval will lose the reasonable certainty, requirement necessary to maintain the volumes assigned to it in the reserves class.

The Camamu/Almada Basin is located offshore from the state of Bahia, northeastern Brazil. The former exploration concession block where Manati and Camarão Norte were discovered, BCAM-40, with approximately 935 km^2, was awarded to Petrobras in 1998. In 1999 Petrobras presented a farm in opportunity for participation in the concession. Since then, QGEP has 45% participating interest in each field. Both of them are in shallow waters, approximately 20-50 meters deep and 10-20 km from shore.

Manati Field is a dry gas field which started production in 2007 from the Sergi Fm. Production and pressure performance available as of December 2011 was analyzed through material balance, which indicates, after a cumulative gas production of 8.8 Bm^3, a contacted original gas in place volume (OGIP) of 32.3 Bm^3. This value is lower than the volumetric OGIP estimate of 40.15 Bm^3 presented by QGEP. The difference has been interpreted to indicate the existence of in place gas that is not being influenced by the existing six producing wells. The material balance OGIP estimate was the basis of the Proved reserves estimate while the volumetric estimate was used for the 2P and 3P estimates.

In order to estimate recovery factors for those in place volumes, QGEP presented simulation runs that match the production and pressure histories and forecast an ultimate abandonment field pressure. Two forecasts based on the Proved OGIP, one without and one with late compression starting in 2014, were the basis of the Proved Developed Producing and the Total Proved reserves respectively. A forecast using the volumetric OGIP and also the late compression established the 3P estimate. The 2P estimate included 25% of the difference with the 1P case. In order to contact the unproved volumes, a seventh well is planned for 2016. The average calorific value of the gas is 999 Btu/scf while the gas-condensate ratio (GOR) reached 63,000v/v in 2011.

This audit examination was based on information provided by QGEP to GCA through June 1, 2012, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the course of the audit process were resolved to our satisfaction. Production and pressure history throughout 2011 and material balance estimates coupled with the geological and simulation models of the field constitute the basics of the methodology applied.

The commerciality and economic tests for the December 31, 2011 reserves volumes were based on QGEP's future scenario of oil and gas which gives realized condensate and gas sales prices as shown in the following table. Gas prices are based on the sales contract, which establishes escalation on the basis of the Brazil market inflation estimated to grow 5.24% in 2012, 5% in 2013 and 3% per year afterwards in this forecast. Condensate prices reflect an additional premium of US$ 8.00/Bbl to the Brent crude oil price as advised by QGEP.

Both gas and condensate prices have been grossed up for taxes, which are 21.25% for gas (PIS, PASEP, COFINS and ICMS taxes) and 9.25% for condensate (PIS, COFINS).

Year	Condensate US$/Bbl	Gas US$/MMBtu
2012	134.99	9.25
2013	135.54	9.73
2014	135.54	10.22
2015	141.05	10.52
2016	143.69	10.84
2017	146.39	11.17
Thereafter	+2% per year	+3% per year

Future capital costs were derived from development program forecasts for the field. Recent historical operating expense data were utilized as the basis for operating cost projections. GCA has found that projected capital investments and operating expenses are sufficient to economically produce the projected volumes. Cashflows are included in Appendix II.

It is GCA's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes at December 31, 2011 are, in the aggregate, reasonable and the reserves categorization is appropriate and consistent with the definitions for reserves set out in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers in March 2007 and attached here as Appendix I. GCA concludes that the methodologies employed by QGEP in the derivation of the volume estimates are appropriate and that the quality of the data relied upon, the depth and thoroughness of the estimation process is adequate.

GCA is not aware of any potential changes in regulations applicable to these fields that could affect the ability of QGEP to produce the estimated reserves.

This assessment has been conducted within the context of GCA's understanding of QGEP's petroleum property rights as represented by QGEP management. GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties or interests.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any reserve or resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserve and resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

For this assignment, GCA served as an independent reserve and resource auditor/evaluator. The firm's officers and employees have no direct or indirect interest holdings in the property units evaluated. GCA's remuneration was not in any way contingent on reported reserve or resource estimates.

Finally, please note that QGEP will obtain GCA's prior written or email approval for the use with third parties and context of the use with third parties of any results, statements or opinions expressed by GCA to QGEP, which are attributed to GCA. Such requirement of approval shall include, but not be confined to, statements or references in documents of a public or semi-public nature such as loan agreements, prospectuses, reserve statements, websites, press releases, etc.

Very truly yours,

GAFFNEY, CLINE & ASSOCIATES, INC.

Roberto Wainhaus
Lead Reservoir Engineer

David K Morgan
Peer reviewer - Principal

Attachments

Appendices	I:	Petroleum Resources Management System Definitions and Guidelines
	II:	Cashflows

APPENDICES

Appendix I:

Petroleum Resources Management System Definitions and Guidelines

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:

www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see “2001 Supplemental Guidelines,” Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,

(2) wells which were shut-in for market conditions or pipeline connections, or

(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,

(2) from deepening existing wells to a different (but known) reservoir,

(3) from infill wells that will increase recovery, or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

  (a) recomplete an existing well or

  (b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

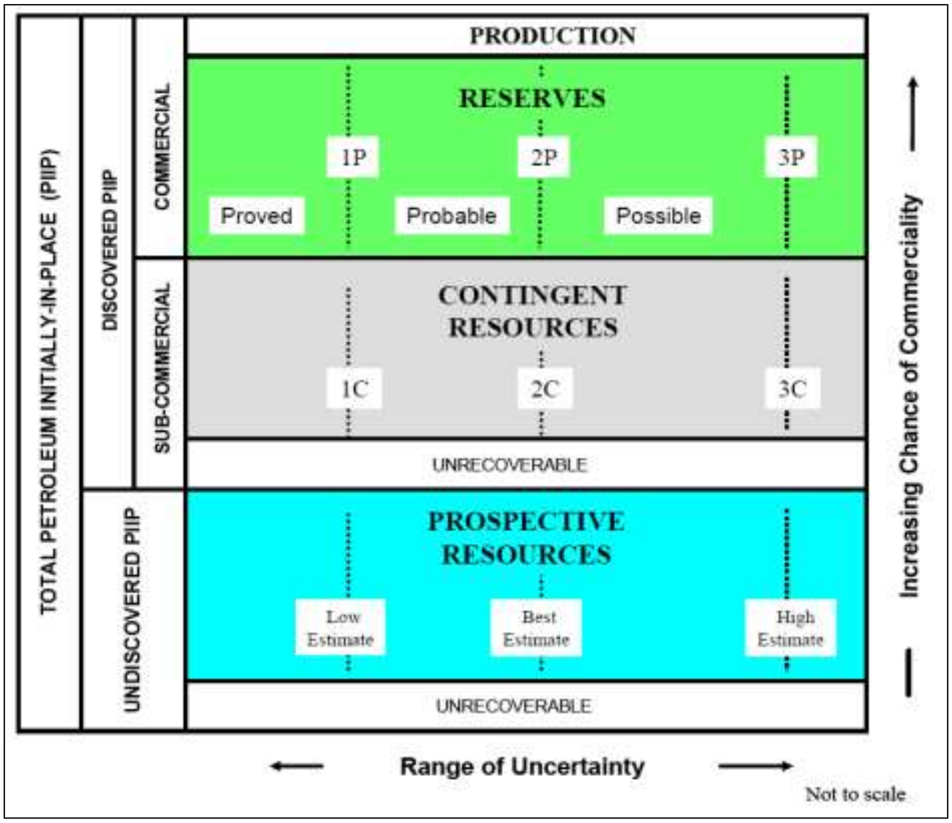
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

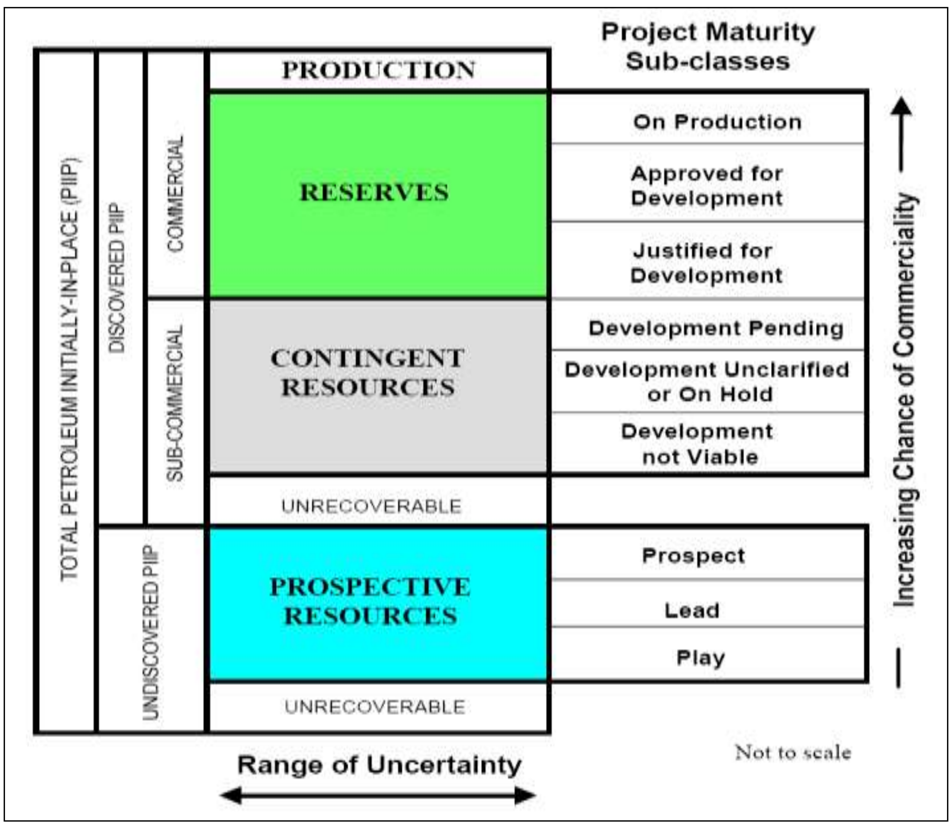
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY



Appendix II:

Cashflows

Queiroz Galvão Exploração e Produção Net Interest Reserve Cashflows
as of December 31, 2011
Manati Field

Proved Developed Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow	Income Tax Social Contr.	AIT Net Cashflow	10% AIT Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2012	97	34.8	134.99	9.25	335	25	70	8	30			202	192	15	187	178
2013	95	34.8	135.54	9.71	351	26	73	9	22			220	191	17	203	176
2014	81	30.0	135.54	10.00	311	23	65	7	23			193	152	14	179	141
2015	65	24.4	141.05	10.30	261	20	54	4	24			159	114	12	147	106
2016	50	19.0	143.69	10.61	209	16	44	1	25			124	81	10	115	75
2017	39	14.9	146.39	10.93	168	13	35		25			95	56	11	84	50
2018	30	11.5	149.32	11.26	134	10	28		26			70	38	8	61	33
2019	21	8.0	152.30	11.59	96	7	20		27			42	20	5	37	18
2020	14	5.6	155.35	11.94	69	5	14		28			22	10	3	19	8
2021											72	-72	-29		-72	-29
2022																
2023																
2024																
2025																
2026																
2027																
Total	492	183.0			1,933	145	402	29	230		72	1,055	825	95	960	755

Total Proved (1P Case) Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow	Income Tax Social Contr.	AIT Net Cashflow	10% AIT Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2012	97	34.8	134.99	9.25	335	25	70	9	30	7		194	185	17	176	168
2013	95	34.8	135.54	9.71	351	26	73	10	22	14		204	177	19	185	161
2014	88	32.7	135.54	10.00	339	25	71	9	36	6		192	151	17	175	138
2015	88	33.5	141.05	10.30	357	27	74	10	37			209	150	18	191	137
2016	86	33.2	143.69	10.61	365	27	76	10	39			213	139	19	194	127
2017	76	29.9	146.39	10.93	337	25	70	8	40			194	115	24	170	101
2018	65	25.9	149.32	11.26	302	23	63	5	41			170	91	21	149	80
2019	56	22.4	152.30	11.59	268	20	56	3	42			147	72	19	128	63
2020	48	19.4	155.35	11.94	239	18	50	1	43			126	56	16	110	49
2021	41	16.8	158.46	12.30	213	16	44		45			108	43	14	94	38
2022	34	14.2	161.63	12.67	185	14	39		46			87	32	11	75	28
2023	23	9.3	164.86	13.05	126	9	26		47			43	14	5	37	12
2024	16	6.8	168.15	13.44	94	7	20		49			19	6	3	16	5
2025											85	-85	-24		-85	-24
2026																
2027																
Total	814	313.6			3,510	263	732	66	518	27	85	1,819	1,207	204	1,615	1,081

2P Case Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow	Income Tax Social Contr.	AIT Net Cashflow	10% AIT Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2012	97	34.8	134.99	9.25	335	25	70	10	30	7		194	185	17	176	168
2013	95	34.8	135.54	9.71	351	26	73	11	22	14		204	177	19	185	161
2014	88	32.7	135.54	10.00	339	25	71	9	36	6		192	151	17	175	138
2015	88	33.5	141.05	10.30	357	27	74	10	37			209	150	18	190	136
2016	86	33.3	143.69	10.61	366	27	76	10	39	14		200	130	19	181	118
2017	78	30.6	146.39	10.93	346	26	72	8	40			200	118	25	175	104
2018	68	26.8	149.32	11.26	312	23	65	6	41			177	95	22	155	83
2019	58	23.3	152.30	11.59	278	21	58	4	42			154	75	19	134	66
2020	50	20.2	155.35	11.94	249	19	52	2	43			133	59	17	116	51
2021	43	17.5	158.46	12.30	222	17	46		45			114	46	15	99	40
2022	36	14.9	161.63	12.67	195	15	41		46			93	34	12	81	30
2023	26	10.7	164.86	13.05	144	11	30		47			56	19	7	49	16
2024	19	7.9	168.15	13.44	109	8	23		49			29	9	4	25	8
2025	12	4.9	171.52	13.84	70	5	15		50			0	0		0	0
2026											88	-88	-22		-88	-22
2027																
Total	843	325.7			3,671	275	765	68	569	40	88	1,865	1,226	211	1,654	1,097

3P Case Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow	Income Tax Social Contr.	AIT Net Cashflow	10% AIT Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2012	97	34.8	134.99	9.25	335	25	70	10	30	7		193	184	18	176	168
2013	95	34.8	135.54	9.71	351	26	73	11	22	14		204	177	19	185	160
2014	88	32.7	135.54	10.00	339	25	71	9	36	6		191	151	17	174	137
2015	88	33.5	141.05	10.30	357	27	74	10	37			209	149	19	190	136
2016	87	33.5	143.69	10.61	367	28	77	10	39	14		201	131	19	182	119
2017	84	32.9	146.39	10.93	372	28	78	10	40			217	128	28	189	112
2018	74	29.4	149.32	11.26	342	26	71	8	41			197	106	25	172	92
2019	64	25.9	152.30	11.59	310	23	65	6	42			174	85	22	152	74
2020	55	22.5	155.35	11.94	277	21	58	3	43			152	68	20	132	59
2021	48	19.6	158.46	12.30	249	19	52	2	45			132	53	17	115	46
2022	41	17.1	161.63	12.67	224	17	47		46			114	42	15	99	36
2023	35	14.7	164.86	13.05	198	15	41		47			94	31	13	82	27
2024	26	11.0	168.15	13.44	152	11	32		49			60	18	8	52	16
2025	17	7.2	171.52	13.84	103	8	22		50			23	6	3	20	6
2026											99	-99	-25		-99	-25
2027																
Total	900	349.6			3,976	298	829	77	569	40	99	2,063	1,306	242	1,821	1,164

Currency in millions of US Dollars

GCA Engineer:	RW	Approved:	DKM