Gaffney, Cline & Associates

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April 22, 2020

Mr. Pablo Creta
Chief Financial Officer
Interoil Colombia Exploration & Production
Carrera 7 No. 113 - 43
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Bogotá, Colombia

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Dear Mr. Creta:

This reserves statement has been prepared by Gaffney, Cline & Associates (GCA) at the request of INTEROIL COLOMBIA EXPLORATION & PRODUCTION (Interoil or "the Client"), covering Interoil´s participation in areas located in the Golfo San Jorge Basin, Chubut province of Argentina, as specified in the following table:

Table 1

Interoil´s Participation Interest in the Area, Chubut Province, Argentina as of December 31, 2019

Province	Area	Working Interest (%)	Operator
Chubut	Mata Magallanes Oeste	80.0	Interoil

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

GCA has conducted an independent audit examination, as of December 31, 2019, of the previously mentioned area. On the basis of technical and other information made available to GCA concerning this property unit, GCA hereby provides the reserves statement in the following Table 2.

In compliance with your instructions, and the accepted definitions for reserves, we have evaluated the Mata Magallanes Oeste asset as of December 31, 2019, using a reasonable oil price outlook as of that date.

We would note that since the effective date various events have resulted in a material downward movement in the current oil price. If the current oil prices remain low and the long term oil price outlook is revised downward, there may be a material revision to the volumes classified as reserves as well as the NPVs summarized in this report.

Table 2

Statement of Remaining Oil and Gas Reserves
Mata Magallanes Oeste Area in Chubut, Argentina
as of December 31, 2019

Reserves	Gross (100%) Field Volumes			Gross (WI) Company Volumes			Net Revenue Interest Company Volumes		
	Liquids (MBbl)	Gas (MMcf)	Gas Sales (MMcf)	Liquids (MBbl)	Gas (MMcf)	Gas Sales (MMcf)	Liquids (MBbl)	Gas (MMcf)	Gas Sales (MMcf)
Proved									
Developed	496	-	-	397	-	-	349	-	-
Undeveloped	393	-	-	314	-	-	277	-	-
Total Proved	**889**	**-**	**-**	**711**	**-**	**-**	**626**	**-**	**-**
Probable	919	-	-	735	-	-	647	-	-
Possible	838	-	-	671	-	-	590	-	-

Notes:

1. Gross (100%) volumes are 100% of the field volumes estimated to be commercially recoverable under the intended development plan.
2. Gross (WI) company volumes represent Interoil's working interest remaining volumes before deduction of royalties.
3. Net (NRI) company volumes represent Interoil's net revenue interest remaining volumes after deduction of royalties.
4. Associated gas volumes are not categorized as reserves since there are not firm signed contracts in place for sales.
5. The above remaining hydrocarbon volumes include volumes estimated to be commercially recoverable through to the end of the concessions contract.
6. Totals may not exactly equal the sum of the individual entries due to rounding.

Hydrocarbon liquid volumes represent crude oil estimated to be recovered and are reported in thousands (10^3) barrels at stock tank conditions (MBbl). Natural gas volumes are reported in millions (10^6) of cubic feet (MMcf) at standard conditions of 14.7 psi and 60°F.

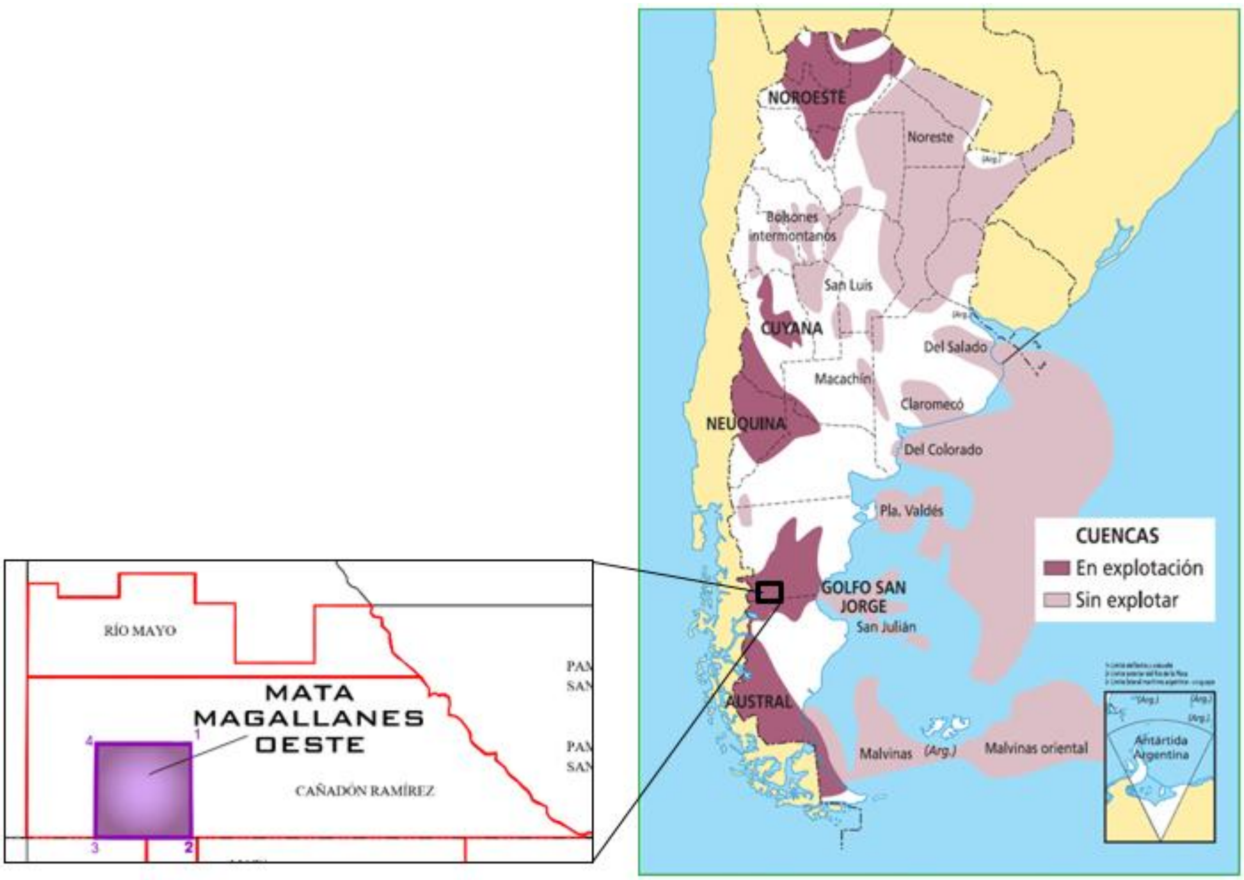
Interoil acquired the rights in the area in 2019 and become the Operator; the contract expires in April 2043. Interoil holds 80% working interest (WI) in the block. Royalties payable to the provincial states are 12%.

Net cashflow statements are presented in Appendix I.

Royalties payable to the province have been deducted from reported net interest volumes.

The Figure 1 shows the geographical location of the Mata Magallanes Oeste area, Province of Chubut. The area is located in the Golfo San Jorge Basin.

Figure 1: Golfo San Jorge Basin and Mata Magallanes Oeste Area Location Map



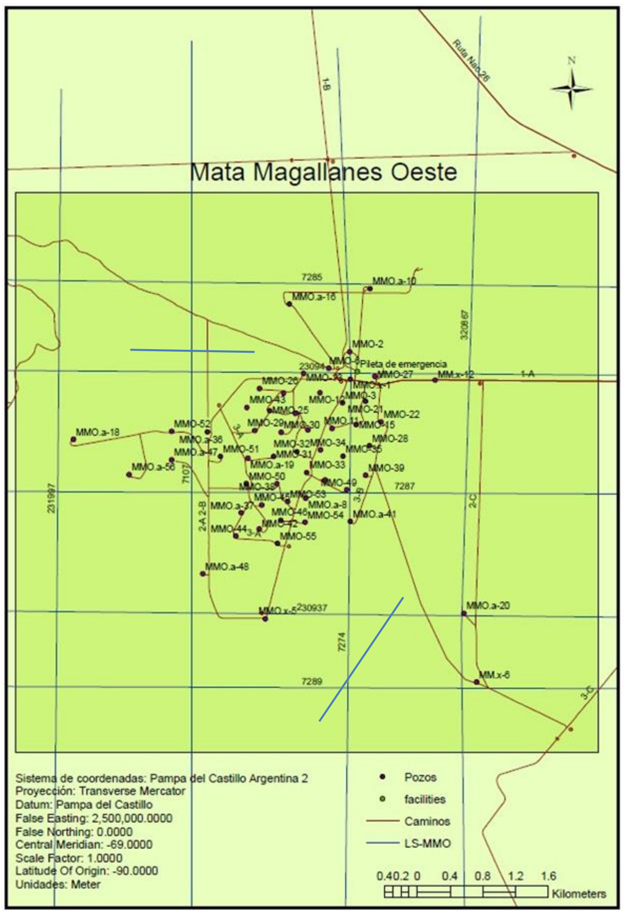
Source: Interoil

Mata Magallanes Oeste Area

The Mata Magallanes Oeste Block cover about 48.3 km^2. The field was discovered and developed in the 80’s. As of December 2019, 55 wells have been drilled, 6 of them are still active producing a total rate of 57 bpd of oil and 77.2 Mcfd associated gas (GOR 1,347 cf/bbl), with 93% wcut. The gravity of oil is around 20^O API

The following Figure 2 shows a map of the field with well locations.

Figure 2: Tierra del Fuego Areas Location Map



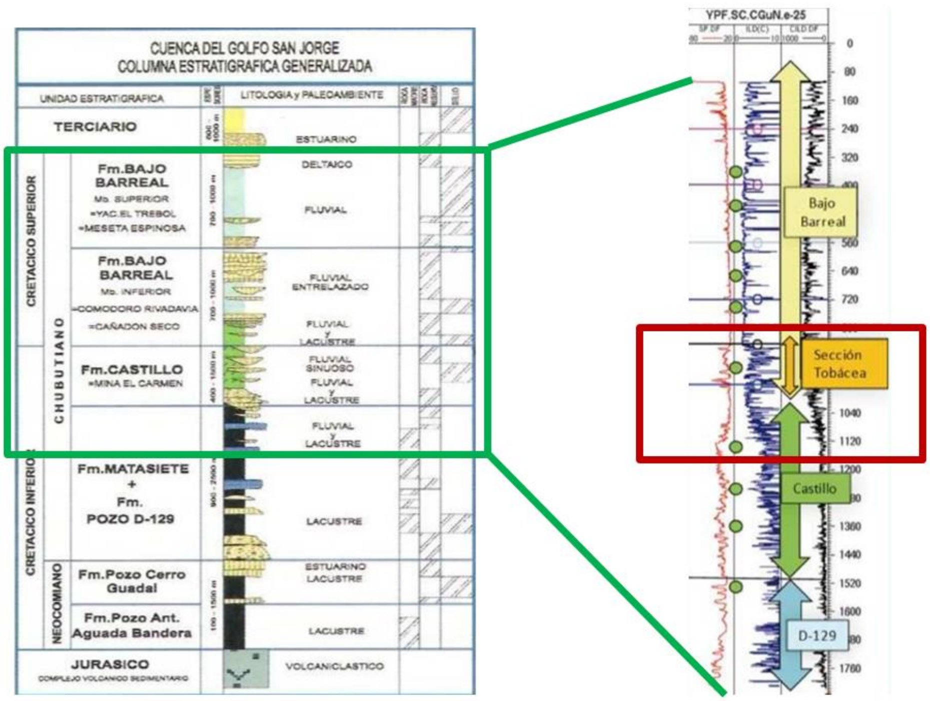
Source: Interoil

The Mata Magallanes Oeste block is located in the west side of Golfo de San Jorge Basin, the productive Formations are Matasiete, Castillo and Bajo Barreal from Cretaceous age (Fig. 3).

Matasiete Formation is not important for production, almost the 88% of the oil cumulated is coming from Castillo and Bajo Barreal formations, both are composed by sandstones and interbeded siltstones in an ancient fluvial sedimentary environment.

The reservoirs are sandstones with argillaceous and tuffaceous matrix with fair to poor porosity properties becoming more compact as depth increase.

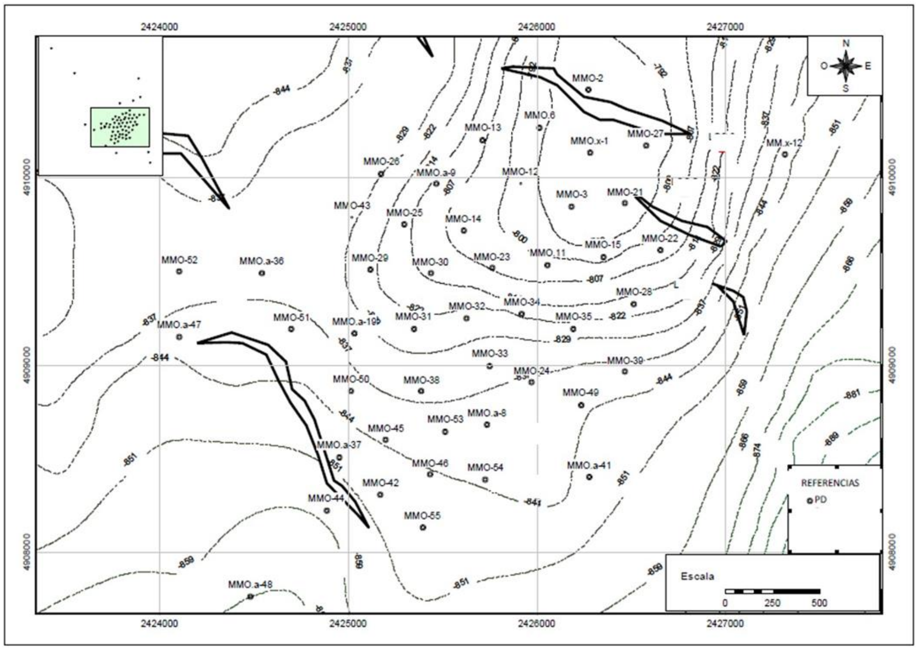
Figure 3: Stratigraphic Colum Golfo San Jorge Basin



Source: Interoil

The main structural features at Cretaceous Formations levels are large folds associated to compresional faulting. The structural map at top of Castillo Formation in Mata Magallanes Oeste field is show in Figure 4, the field is located in the SE corner of the block and covers around 12 km^2.

Figure 4: Mata Magallanes Oeste Structural Map Top Castillo Formation



Source: Interoil

Proved Developed Producing (PDP) reserves were estimated using decline analysis.

Interoil has started a plan to reactivate inactive wells and optimize the field status. The plan includes the reactivation of 10 shut-in wells, replace production installation (pulling) in 8 wells and repair another 6 wells (perforation of non-open sandstones).

Capital investment for pulling job is 95 MUS$/well and for the workover 350 MUS$/well. Volumes have been estimated based on similar previous jobs and average expected performance of the wells.

Proved Developed Non Producing (PDNP) reserves includes the reactivation of 14 wells and 3 workovers. The remaining 4 reactivations and 3 workovers have been categorized as Probable reserves (PB).

Interoil has also plans for a drilling campaign of 10 wells in the next 5 years. The drilling and completion costs reach 1,900 MUS$/well; completion include hydraulic fractures to optimize future performance. Volume was obtained from a type curve based on performance of existing wells in the area; the incremental production expected due to hydraulic fracture has been estimated based on analogy of similar jobs in near fields.

Three locations have been categorized as Proven Non Developed (PND), three Probable (PB) and four Possible (PS). Due to the fact that up today no hydraulic jobs have been performed in the block, such incremental have been categorized as Probable, Possible and Contingent Resource for each of the proposed Proved Non Developed, Probable and Possible locations, respectively.

Additional facilities costs total MUS$ 400 gross. Estimated abandonment cost is MUS$ 100/well.

An average of the recent GOR value was applied to estimate the future associated gas volumes. Currently the produced gas is consumed in field operations.

Contingent Resources

GCA has conducted an independent audit examination, as of December 31, 2019, of the crude oil and natural gas contingent resources on Mata Magallanes Oeste concession.

The crude oil volumes are resulting from the potential incremental production in four Possible locations to be drilled, due to successful hydraulic fracture jobs to be performed. Hydraulic fracture have not been tested yet in the Mata Magallanes Oeste field, at its particular conditions, as a successful procedure to increase recoverable volumes.

Gas volumes are estimated based on average GOR and projected oil volumes. There are not signed sales contract for gas at this time, the gas produced is consumed in the field. However, Interoil has indicated that this situation may change in the future and a portion of the incremental produced gas resulting from the future development might be sale. For this reason, associated gas volumes are categorized as Contingent Resources, discounting internal consumption for the normal field operation. Interoil has estimated a future annual gas consumption of 84.7 MMcf/Year

On the basis of technical and other information made available to GCA concerning this property unit, GCA hereby provides the contingent resources statements in the following tables:

Table 4. Gross Contingent Resources Statement of Contingent Resources of Mata Magallanes Oeste Concession as of December 31,2019

1C		2C		3C	
Liquids MBbl	Gas MMcf	Liquids MBbl	Gas MMcf	Liquids MBbl	Gas MMcf
842.8	201.9	0.0	965.0	0.0	1,825.4

Table 5. Working Interest Contingent Resources Statement of Contingent Resources of Mata Magallanes Oeste Concession as of December 31,2019

1C		2C		3C	
Liquids MBbl	Gas MMcf	Liquids MBbl	Gas MMcf	Liquids MBbl	Gas MMcf
674.2	161.5	0.0	772.0	0.0	1,460.3

Notes:

1. Gross Concession volumes represent 100% of the contingent resources volumes estimated to be recoverable from the concession under the intended contingent development plans.
2. Working interest (WI) volumes represent contingent resources volumes to the working interest of Interoil in the concession.
3. Royalties payable to Provinces have not been deducted from reported working interest (WI) contingent resources volumes.
4. Gas includes Sales Gas; projected gas consumption has been deducted.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in thousands of stock tank barrels (MBbl). Natural gas volumes represent expected gas sales and are reported in million (10^6) standard cubic feet at standard condition of 14.7 psia and 60°F. The gas volumes have been reduced for projected fuel usage in the concession. Royalties payable to Provinces have not been deducted from reported working interest volumes.

Reserves and Resources Assessment

This audit examination was based on reserves and resources estimates and other information provided by Interoil to GCA through December 2019, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the audit process were resolved to GCA's satisfaction.

The economic tests for reserves were based on Interoil's future scenario of crude oil prices. All prices and costs are quoted in US dollars. The following table shows average liquid prices.

Table 5: Crude Oil Prices Outlook

Year	Oil US$/Bbl	Year	Oil US$/Bbl
2020	41.27	2031	46.48
2021	41.72	2032	46.98
2022	42.17	2033	47.48
2023	42.63	2034	48.00
2024	43.10	2035	48.51
2025	43.57	2036	49.04
2026	44.04	2037	49.56
2027	44.52	2038	50.10
2028	45.00	2039	50.63
2029	45.49	2040	51.18
2030	45.98	2041+	51.18

Future capital costs were derived from development program forecasts prepared by Interoil. Recent historical operating expense data were used as the basis for operating cost projections. Operating expenses include field operating expenses and transportation directly related to the production or development of the concession. No inflation was considered in these costs.

GCA has found that Interoil has projected sufficient capital investments and operating expenses to economically produce the projected volumes. Cash flow analyses by reserves category are provided in Appendix I.

GCA concludes that the methodologies employed by Interoil in the derivation of the reserves and resources estimates are appropriate, and that the quality of the data relied upon and the depth and thoroughness of the reserves and resources estimation process is adequate.

Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GCA has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 v1.01 (see Appendix II).

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 resources assessments 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 resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resources 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, resources 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.

Hydrocarbon liquid volumes represent crude oil and condensate estimated to be recovered during field separation and plant processing and are reported in thousands (10^3) barrels at stock tank conditions (MBbl). Natural gas volumes are reported in millions (10^6) of cubic feet (MMcf) at standard conditions of 14.7 psi and 60°F.

GCA's review and audit involved reviewing pertinent facts, interpretations and assumptions made by Interoil or others in preparing estimates of reserves and resources. GCA performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

GCA prepared an independent assessment of the reserves based on data and interpretations provided by Interoil.

Definition of Reserves and Resources

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

GCA is not aware of any potential changes in regulations applicable to this concession that could affect the ability of Interoil to produce the estimated reserves.

Reserves 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 development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any net present value (NPV) analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident 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.

GCA has not undertaken a site visit and inspection because it was not included in the project scope. As such, GCA is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GCA is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Use of Net Present Values

It should be clearly understood that the NPVs contained herein do not represent a GCA opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Proved and/or Probable and/or Possible reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs presented herein.

Qualifications

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with Interoil. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

Notice

This document is confidential and has been prepared for the exclusive use of the Client or parties named herein. It may not be distributed or made available, in whole or in part, to any other company or person without the prior knowledge and written consent of Gaffney, Cline & Associates (GCA). No person or company other than those for whom it is intended may directly or indirectly rely upon its contents. GCA is acting in an advisory capacity only and, to the fullest extent permitted by law, disclaims all liability for actions or losses derived from any actual or purported reliance on this document (or any other statements or opinions of GCA) by the Client or by any other person or entity.

Gaffney, Cline & Associates

Alejandro Giaquinta, Project Manager

Reviewed by
Eduardo Sanchez, Principal Advisor

Appendices

Appendix I	Net Cash Flows
Appendix II	PRMS Guidelines and Reserves Definitions
Appendix III	Glossary

Appendix I
Net Cash Flows

Gaffney, Cline & Associates

Interoil Net Revenue Interest Cashflows
as of December 31, 2019
Mata Magallanes Oeste

Proved Developed Reserves (PD)

Year	Sales Profiles Liquids	Sales Profiles Gas	Gross Income	Provincial Tax	Operating Expenses	Capital Investment	Abandon-ment Cost	Net Cashflow	10% Discounted Net Cashflow
	MBbl	MMcf	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M
2020	32.1		1,323	45	522	636		120	114
2021	42.6		1,778	61	557	508		652	565
2022	45.7		1,926	66	547	228		1,084	855
2023	41.8		1,781	61	524			1,196	857
2024	34.8		1,498	51	483			965	628
2025	29.2		1,274	43	450			781	462
2026	24.9		1,096	37	424			635	342
2027	21.4		950	32	403			515	252
2028	18.4		829	28	385			415	185
2029	15.7		716	24	369			322	130
2030	13.5		620	21	356			243	89
2031	11.4		531	18	343			170	57
2032	9.8		459	16	333			110	33
2033	8.0		380	13	323			44	12
2034							2,400	(2,400)	(603)
2035									
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
TOTAL	**349.2**	**0.0**	**15,160**	**517**	**6,019**	**1,372**	**2,400**	**4,852**	**3,979**

Total Proved Reserves (1P)

Year	Sales Profiles Liquids	Sales Profiles Gas	Gross Income	Provincial Tax	Operating Expenses	Capital Investment	Abandon-ment Cost	Net Cashflow	10% Discounted Net Cashflow
	MBbl	MMcf	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M
2020	32.1		1,323	45	522	636		120	114
2021	66.9		2,791	95	702	3,548		(1,554)	(1,347)
2022	84.1		3,548	121	777	1,748		903	711
2023	74.7		3,185	109	721			2,356	1,688
2024	56.8		2,450	84	614			1,752	1,141
2025	44.4		1,935	66	540			1,329	787
2026	37.2		1,637	56	497			1,084	584
2027	32.6		1,452	49	470			932	456
2028	28.9		1,301	44	448			809	360
2029	25.5		1,161	40	427			694	281
2030	22.6		1,039	35	410			594	218
2031	19.9		927	32	394			501	167
2032	17.7		832	28	381			423	128
2033	15.4		731	25	367			339	94
2034	13.4		644	22	355			267	67
2035	11.7		569	19	345			204	47
2036	10.3		505	17	337			151	31
2037	9.2		455	16	330			109	21
2038	8.1		406	14	324			69	12
2039	7.3		371	13	319			40	6
2040	6.7		343	12	315			16	2
2041							2,700	(2,700)	(348)
2042									
2043									
TOTAL	**625.7**	**0.0**	**27,605**	**941**	**9,595**	**5,932**	**2,700**	**8,437**	**5,219**

Proved + Probable Reserves (2P)

Year	Sales Profiles		Gross Income	Provincial Tax	Operating Expenses	Capital Investment	Abandon-ment Cost	Net Cashflow	10% Discounted Net Cashflow
	Liquids	Gas							
	MBbl	MMcf	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M
2020	35.7		1,473	50	544	956		(78)	(74)
2021	112.3		4,686	160	1,001	5,424		(1,899)	(1,646)
2022	167.2		7,051	240	1,328	3,828		1,654	1,303
2023	166.3		7,090	242	1,267	1,520		4,061	2,909
2024	121.2		5,222	178	998			4,046	2,635
2025	90.2		3,928	134	813			2,981	1,765
2026	72.9		3,211	109	710			2,392	1,287
2027	63.6		2,832	97	655			2,080	1,018
2028	57.0		2,563	87	615			1,861	828
2029	50.9		2,317	79	579			1,659	671
2030	45.7		2,102	72	548			1,483	545
2031	41.0		1,905	65	520			1,320	441
2032	36.9		1,733	59	495			1,179	358
2033	32.7		1,553	53	470			1,030	284
2034	29.1		1,397	48	449			900	226
2035	26.0		1,263	43	430			789	180
2036	23.4		1,147	39	415			693	144
2037	21.2		1,049	36	401			612	115
2038	19.1		959	33	389			537	92
2039	17.5		885	30	379			475	74
2040	16.1		823	28	371			424	60
2041	14.7		754	26	363			365	47
2042	12.1		621	21	348			252	30
2043							3,700	(3,700)	(394)
TOTAL	**1272.8**	**0.0**	**56,563**	**1,928**	**14,088**	**11,728**	**3,700**	**25,118**	**12,899**

Proved + Probable + Possible Reserves (3P)

Year	Sales Profiles		Gross Income	Provincial Tax	Operating Expenses	Capital Investment	Abandon-ment Cost	Net Cashflow	10% Discounted Net Cashflow
	Liquids	Gas							
	MBbl	MMcf	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M	US$ M
2020	35.7		1,473	50	544	1,195		(317)	(302)
2021	124.5		5,194	177	1,074	6,780		(2,837)	(2,459)
2022	202.5		8,539	291	1,539	6,685		24	19
2023	256.5		10,934	373	1,805	5,700		3,057	2,190
2024	192.3		8,287	283	1,422	1,900		4,683	3,049
2025	146.6		6,388	218	1,150			5,020	2,972
2026	112.0		4,934	168	943			3,823	2,057
2027	94.2		4,192	143	837			3,213	1,572
2028	83.8		3,770	129	775			2,866	1,275
2029	75.7		3,442	117	726			2,598	1,050
2030	68.8		3,162	108	685			2,369	871
2031	62.5		2,904	99	648			2,157	721
2032	56.9		2,675	91	615			1,969	598
2033	51.4		2,440	83	582			1,775	490
2034	46.5		2,233	76	553			1,604	403
2035	42.3		2,051	70	527			1,454	332
2036	38.5		1,890	64	505			1,320	274
2037	35.3		1,749	60	486			1,204	227
2038	32.3		1,619	55	468			1,096	188
2039	29.8		1,507	51	453			1,003	156
2040	27.5		1,409	48	439			921	131
2041	25.4		1,300	44	427			829	107
2042	22.1		1,130	39	407			685	80
2043							4,100	(4,100)	(437)
TOTAL	**1863.0**	**0.0**	**83,220**	**2,837**	**17,608**	**22,260**	**4,100**	**36,415**	**15,565**

Appendix II
PRMS Guidelines and Reserves Definitions

**Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers**

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
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: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves 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 the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that 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 five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is 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 maturity and economic 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.

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	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.	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 (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (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.
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 owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. 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 the economic status.

Class/Sub-Class	Definition	Guidelines
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 reclassification 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 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 commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, 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 Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of 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 further data acquisition or studies on the project for the foreseeable future.

Class/Sub-Class	Definition	Guidelines
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic 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 geologic 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 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 geologic 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 that requires more data acquisition and/or evaluation 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 geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	**Guidelines**
Developed Reserves	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	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (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.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	**Guidelines**
Proved Reserves	Those quantities of petroleum that, 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 (P90) 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 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 in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. 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	Those additional Reserves that analysis of geoscience and engineering data indicates 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.

Category	Definition	**Guidelines**
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates 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 (P10) 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 economic production from the reservoir by a defined, commercially mature 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 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 mature and economically 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 elevation and there exists the potential for an associated gas cap, Proved Reserves of oil 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.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

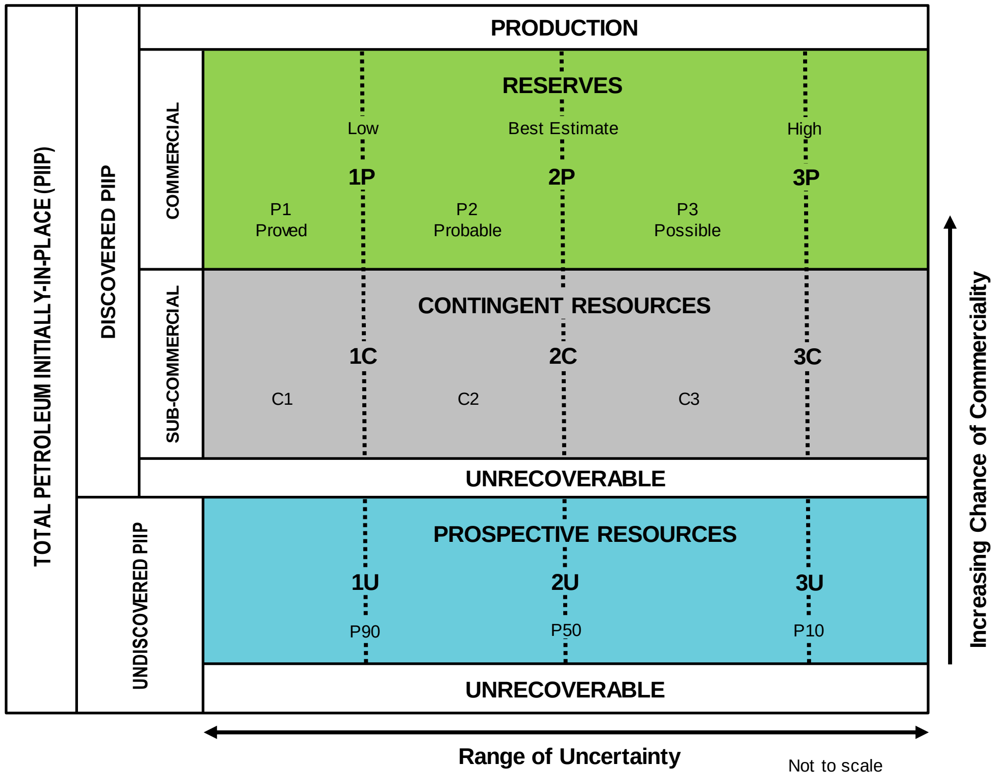
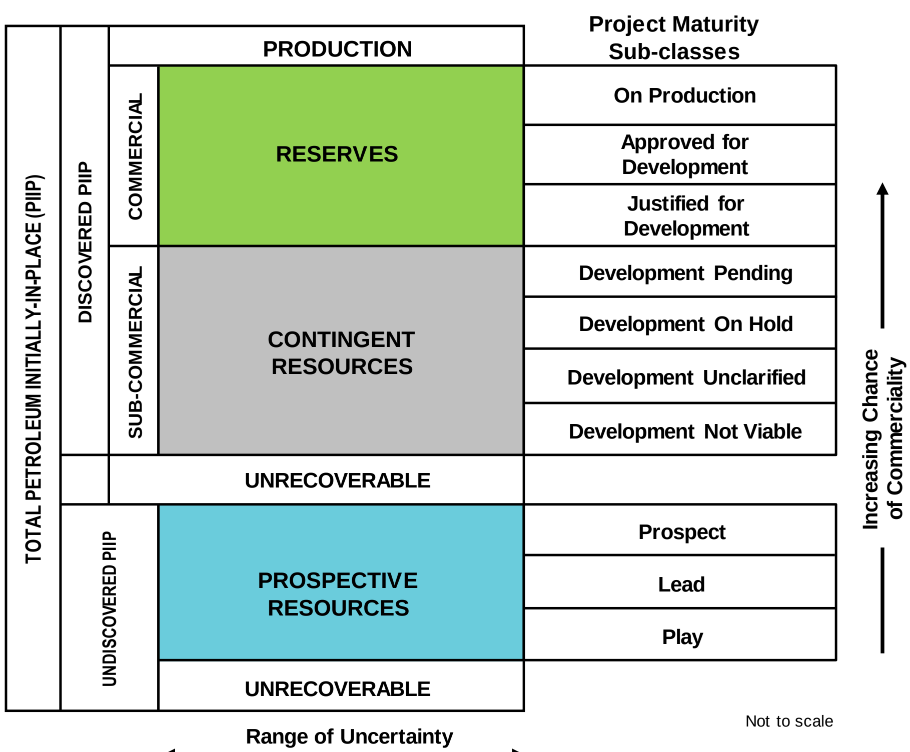


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix III
Glossary

Glossary – Standard Oil Industry Terms and Abbreviations

%	Percentage
1H05	First half (6 months) of 2005 (example)
2Q06	Second quarter (3 months) of 2006 (example)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
ºAPI	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day

bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
D1BM	Design 1 Build Many
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DLIS	Digital Log Interchange Standard
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal

E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
ECS	Elemental Capture Spectroscopy
EI	Entitlement Interest
EIA	Environmental Impact Assessment
ELT	Economic Limit Test
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
FSO	Floating Storage and Offloading
FWL	Free Water Level
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GCoS	Geological Chance of Success
GDT	Gas Down to
GIIP	Gas Initially In Place
GJ	Gigajoules (one billion Joules)

GOC	Gas Oil Contact
GOR	Gas Oil Ratio
GRV	Gross Rock Volumes
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LAS	Log ASCII Standard
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas

LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3/d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3/d	Thousand Cubic metres per day
MM	Million
MMm^3	Million Cubic metres
MMm^3/d	Million Cubic metres per day
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely

Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NTG	Net/Gross Ratio
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil-Down-To
OGIP	Original Gas in Place
OIIP	Oil Initially In Place
OOIP	Original Oil in Place
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
Phie	effective porosity
PI	Productivity Index
PIIP	Petroleum Initially In Place
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch

psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure, Volume and Temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
RF	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R/P	Reserve to Production
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPM	Single Point Mooring
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPS	Subsea Production System
SS	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
Swi	irreducible water saturation
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
UFR	Umbilical Flow Lines and Risers
USGS	United States Geological Survey
US$	United States dollar
VLCC	Very Large Crude Carrier
Vsh	shale volume
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent