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TG/EE023620/sf **4th February, 2011**

The Directors,
JSC KazMunaiGas Exploration Production,
17, Kabanbay Batyr Ave.,
Astana 010000,
Republic of Kazakhstan.

Dear Sirs,

AN ASSESSMENT OF RESERVES AS AT 31st DECEMBER, 2010

INTRODUCTION

Gaffney, Cline & Associates (GCA), on behalf of Joint Stock Company KazMunaiGas Exploration Production (KMG EP), has updated as at 31st December, 2010 GCA's 31st December, 2009 independent Reserves assessment for certain oilfields operated by the production affiliates EmbaMunaiGas (EMG) and OzenMunaiGas (OMG). This letter summarises the main results and conclusions. No estimates are included for Contingent or Prospective Resources in this summary letter.

GCA is also auditing on behalf of KMG EP certain technical information related to recent discoveries, appraisal drilling and exploration prospects under license to the Company. GCA is still in the process of auditing this information and will be issuing a full technical report later in 2011 that presents the Reserves summarised in this letter, as well as any Contingent Resources and Prospective Resources that may be identified.

The locations of the main fields are shown in the regional map in Figure 1. The OMG and EMG fields are located in five separate production units, or NGDUs, and under five different contracts. The EMG fields are shown grouped in four NGDUs in Figure 2. Uaz and Kondybai are located in the Taisogan exploration licence area and for the purposes of this report are included as part of the EMG NGDU KainarMunaiGas.

GCA has held meetings with KMG EP management and technical staff in Astana, Aktau, Atyrau in Kazakhstan and at GCA's offices in the U.K. GCA has also inspected production facilities in Uzen, Nurzhanov and Zhanatalap.

KMG EP has made available to GCA a comprehensive data set of technical and commercial information related to field production, operations, well performance and results of new wells and workovers, together with the draft 2011 Budget, a draft 2011 to 2015 Business Plan, oil transportation costs and other financial data pertaining to the fiscal terms applicable to the licences and contracts. In carrying out this review GCA has relied on this information and other representations made by KMG EP.

FIGURE 1

KAZMUNAIGAS LOCATION MAP

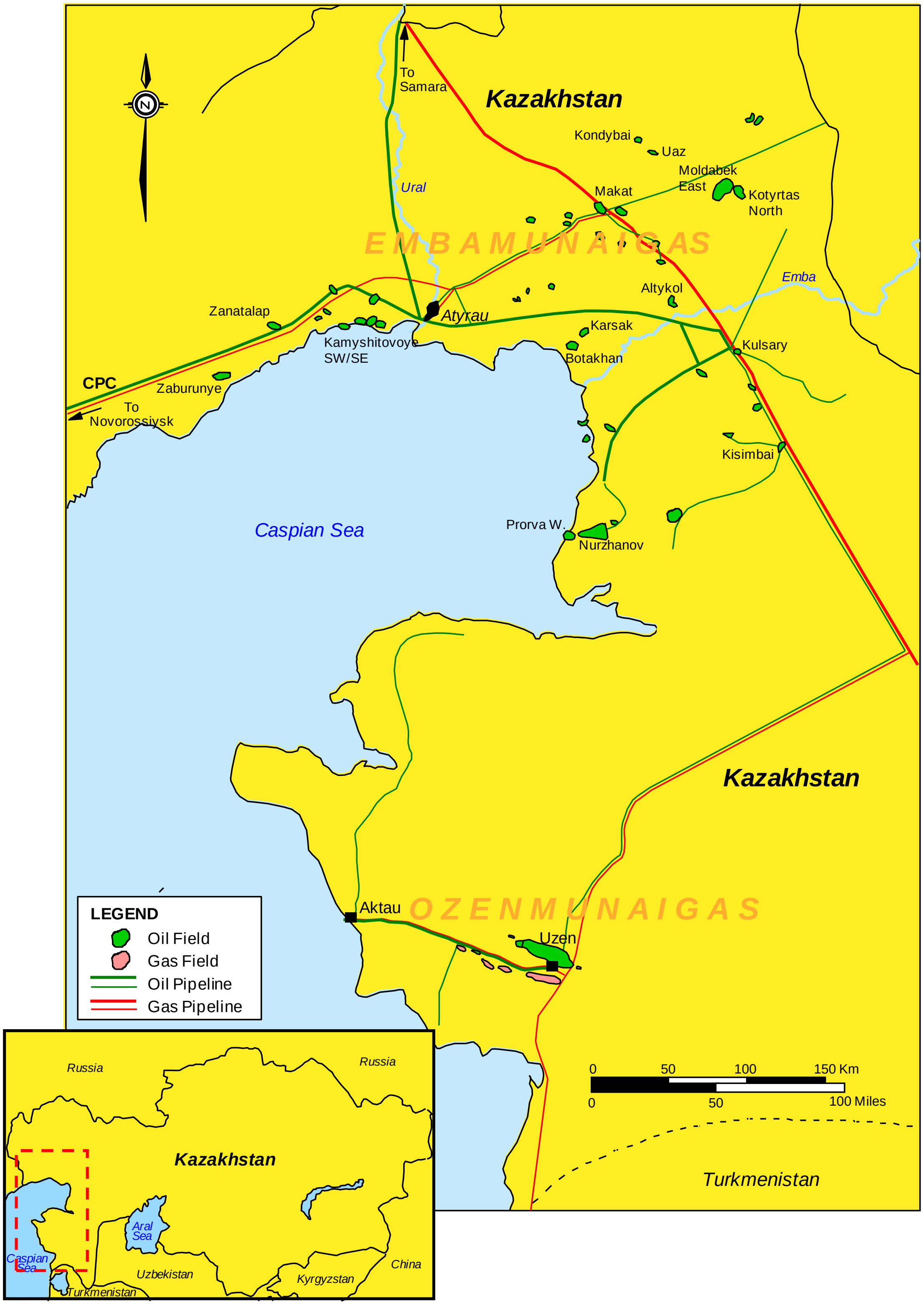


FIGURE 2

EMBAMUNAIGAS NGDU FIELDS AND PIPELINE INFRASTRUCTURE

Production and Reserves are quantified in this report principally in tonnes. For comparison with previous submissions, and to be consistent with generally accepted industry standards, the barrel equivalent Reserves are also stated, using the stock tank oil density for each field as a basis for conversion.

A Glossary of abbreviations, some or all of which may be used in this report, is attached as Appendix I. Reserves have been estimated in accordance with the 2007 Petroleum Resources Management System Definitions and Guidelines (PRMS) of the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers), attached herein as Appendix II.

GCA is an independent energy consultancy specialising in petroleum reservoir evaluation and economic analysis. In the preparation of this report, GCA has maintained, and continues to maintain, a strict consultant-client relationship with KMG EP. The management and employees of GCA have been, and continue to be, independent of KMG EP in the services they provide to the company, including the provision of the opinions expressed in this report. Furthermore, the management and employees of GCA have no interest in any assets or share capital of KMG EP or in the promotion of the company.

SUMMARY AND CONCLUSIONS

The Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves of KMG EP estimated by GCA as of 31st December, 2010 are summarised in the following table.

	Proved Mtonnes	Proved plus Probable Mtonnes	Proved plus Probable plus Possible Mtonnes
Total KMG EP Reserves as at 31st December, 2010	81,657	232,082	265,863

Tables I to 3 summarise the Reserves by field, together with production and Reserves adjustments since the 31st December, 2009 assessment. The barrel equivalent Reserves are summarised by field in Table 4.

Since 31st December, 2009, there has been a net decrease in Proved Reserves of 6,219 Mtonnes (positive Adjustment of 2,547 Mtonnes less 2010 production of 8,766 Mtonnes) and a net decrease in Proved plus Probable Reserves of 2,332 Mtonnes (positive adjustment of 6,434 Mtonnes less 2010 production of 8,766 Mtonnes).

The oil production and expenditure forecasts corresponding to the Proved and Proved plus Probable Reserves estimates given above are presented in Table 5.

Oil production from some of the OMG and EMG fields was affected by severe winter weather conditions during 2010; in addition, an ongoing labour dispute in OMG prevented achievement of the production targets.

KMG EP's proposed drilling plan represents a significant increase over the 2010 Budget and 2011 to 2014 Business Plan, which formed the basis of GCA's previous Reserves assessment as at 31st December, 2009. It is GCA's opinion that this increased drilling commitment will offset any negative impact resulting from the recent weather and labour dispute issues.

The positive Reserves adjustments (before subtraction of production) result primarily from a combination of the increased drilling schedule, higher oil prices (which has extended the economic limit for

TABLE 1

SUMMARY OF PROVED RESERVES AS AT 31ST DECEMBER, 2010

NGDU	Field	Total Proved Reserves at 31st December, 2009 Mtonnes	2010 Production Mtonnes	Adjustments Mtonnes	Total Proved Reserves at 31st December, 2010 Mtonnes	Proved Undeveloped Reserves at 31st December, 2010 Mtonnes
OzenMunaiGas						
	Uzen	62,827	5,565	348	57,610	4,800
	Karamandybas	3,841	401	90	3,531	450
NGDU ZhaikMunaiGas						
	Kamyshitovoye SW	1,835	234	-13	1,588	79
	Zaburunye	1,281	190	1	1,092	124
	Zhanatalap	1,466	183	111	1,393	302
	Kamyshitovoye SE	1,091	142	-39	910	53
	Balgimbayev	861	118	38	781	19
	Gran	471	70	0	401	0
	Novobotinskoye	52	8	14	58	15
	Rovnoye	36	7	3	33	0
NGDU ZhylyoiMunaiGas						
	Nurzhanov	4,105	429	490	4,166	757
	Prorva West	593	88	102	607	90
	Dosmukhambetskoye	593	70	67	591	87
	Aktyube	242	34	37	245	26
	Teren Uzyuk	666	70	5	601	0
	Akingen'	524	79	89	535	176
	Kisimbai	251	31	-12	208	0
	Kulsary	30	4	1	27	0
	Koshagyl	35	4	1	32	0
	Tyulyus	22	3	1	21	0
	Karaton Koshkimbet	55	7	3	51	0
	Akkuduk	167	30	36	173	0
NGDU KainarMunaiGas						
	Moldabek East	2,767	406	635	2,996	362
	Zholamanov	414	46	88	457	212
	North Kotyrtas	167	20	105	252	123
	Uaz	113	10	222	325	232
	Kondybai	26	1	0	25	0
NGDU DossorMunaiGas						
	Botakhan	1,282	185	-43	1,054	0
	Karsak	321	42	30	310	21
	Altykul	134	20	29	143	16
	Baichunas	41	6	1	37	0
	Bek Bike	15	2	17	30	19
	Dossor	3	0	0	2	0
	Iskine	1	0	0	1	0
	Komsomolskoye	5	1	0	4	0
	Koshkar	26	4	1	23	0
	Tanatar	27	4	2	24	0
	Makat East	1,289	221	32	1,100	76
	Makat	5	1	0	5	0
	Zholdybai North	197	31	52	218	27
TOTAL		**87,874**	**8,766**	**2,547**	**81,657**	**8,064**

TABLE 2

SUMMARY OF PROVED PLUS PROBABLE RESERVES AS AT 31ST DECEMBER, 2010

NGDU	Field	Reserves at 31st December, 2009 Mtonnes	2010 Production Mtonnes	Adjustments Mtonnes	Reserves at 31st December, 2010 Mtonnes
OzenMunaiGas					
	Uzen	165,980	5,565	229	160,644
	Karamandybas	10,104	401	35	9,739
NGDU ZhaikMunaiGas					
	Kamyshitovoye SW	6,319	234	60	6,145
	Zaburunye	3,419	190	172	3,401
	Zhanatalap	4,749	183	287	4,852
	Kamyshitovoye SE	3,592	142	-108	3,342
	Balgimbayev	2,640	118	275	2,798
	Gran	1,344	70	80	1,354
	Novobotinskoye	125	8	130	247
	Rovnoye	56	7	4	53
NGDU ZhylyoiMunaiGas					
	Nurzhanov	12,161	429	1,796	13,528
	Prorva West	1,093	88	140	1,145
	Dosmukhambetskoye	1,363	70	175	1,468
	Aktyube	536	34	26	529
	Teren Uzyuk	1,380	70	603	1,913
	Akingen'	817	79	211	949
	Kisimbai	415	31	46	430
	Kulsary	51	4	12	59
	Koshagyl	67	4	26	89
	Tyulyus	37	3	9	44
	Karaton Koshkimbet	96	7	28	117
	Akkuduk	244	30	76	290
NGDU KainarMunaiGas					
	Moldabek East	6,554	406	805	6,953
	Zholamanov	1,119	46	41	1,114
	North Kotyrtas	270	20	249	499
	Uaz	290	10	552	832
	Kondybai	31	1	19	49
NGDU DossorMunaiGas					
	Botakhan	3,812	185	-240	3,387
	Karsak	1,018	42	200	1,176
	Altykul	394	20	66	440
	Baichunas	122	6	9	126
	Bek Bike	39	2	51	88
	Dossor	5	0	0	5
	Iskine	2	0	0	2
	Komsomolskoye	10	1	-1	8
	Koshkar	72	4	6	74
	Tanatar	66	4	5	67
	Makat East	3,529	221	192	3,500
	Makat	7	1	1	7
	Zholdybai North	485	31	163	617
TOTAL		**234,414**	**8,766**	**6,434**	**232,082**

Note:

1. Numbers may not add up due to rounding

TABLE 3

SUMMARY OF PROVED PLUS PROBABLE PLUS POSSIBLE RESERVES AS AT 31ST DECEMBER, 2010

NGDU	Field	Reserves at 31st December, 2009 Mtonnes	2010 Production Mtonnes	Adjustments Mtonnes	Reserves at 31st December, 2010 Mtonnes
OzenMunaiGas					
	Uzen	188,519	5,565	-1,851	181,103
	Karamandybas	11,695	401	-102	11,193
NGDU ZhaikMunaiGas					
	Kamyshitovoye SW	7,347	234	205	7,318
	Zaburunye	4,029	190	231	4,070
	Zhanatalap	5,496	183	420	5,733
	Kamyshitovoye SE	4,328	142	-423	3,764
	Balgimbayev	2,784	118	395	3,061
	Gran	1,550	70	78	1,558
	Novobotinskoye	146	8	147	285
	Rovnoye	62	7	4	59
NGDU ZhylyoiMunaiGas					
	Nurzhanov	14,928	429	2,060	16,558
	Prorva West	1,211	88	166	1,289
	Dosmukhambetskoye	1,478	70	202	1,610
	Aktyube	582	34	41	589
	Teren Uzyuk	2,066	70	347	2,342
	Akingen'	1,206	79	207	1,334
	Kisimbai	625	31	-8	587
	Kulsary	65	4	4	65
	Koshagyl	92	4	10	98
	Tyulyus	47	3	5	49
	Karaton Koshkimbet	125	7	12	129
	Akkuduk	291	30	62	323
NGDU KainarMunaiGas					
	Moldabek East	8,742	406	115	8,451
	Zholamanov	1,237	46	143	1,334
	North Kotyrtas	322	20	298	600
	Uaz	738	10	404	1,132
	Kondybai	35	1	42	76
NGDU DossorMunaiGas					
	Botakhan	4,191	185	-238	3,768
	Karsak	1,064	42	223	1,245
	Altykul	414	20	86	479
	Baichunas	128	6	9	132
	Bek Bike	41	2	68	107
	Dossor	5	0	0	5
	Iskine	2	0	0	2
	Komsomolskoye	11	1	-1	9
	Koshkar	77	4	6	79
	Tanatar	76	4	6	78
	Makat East	4,183	221	604	4,567
	Makat	7	1	1	7
	Zholdybai North	523	31	182	674
TOTAL		**270,469**	**8,766**	**4,160**	**265,863**

Note:

1. Numbers may not add up due to rounding

TABLE 4

SUMMARY OF RESERVES REPORTED IN BARRELS AS AT 31ST DECEMBER, 2010

NGDU	Field	Proved MBbls	Proved plus Probable MBbls	Proved plus Probable plus Possible MBbls
OzenMunaiGas				
	Uzen	425,799	1,187,333	1,307,420
	Karamandybas	26,097	71,981	88,495
NGDU ZhaikMunaiGas				
	Kamyshitovoye SW	11,945	46,232	55,060
	Zaburunye	7,692	23,957	28,670
	Zhanatalap	10,106	35,200	41,594
	Kamyshitovoye SE	6,541	24,025	27,057
	Balgimbayev	5,494	19,686	21,534
	Gran	3,125	10,543	12,130
	Novobotinskoye	455	1,940	2,237
	Rovnoye	232	379	424
NGDU ZhylyoiMunaiGas				
	Nurzhanov	29,944	97,245	119,026
	Prorva West	4,339	8,187	9,215
	Dosmukhambetskoye	4,365	10,851	11,898
	Aktyube	1,821	3,935	4,381
	Teren Uzyuk	4,117	13,108	16,047
	Akingen'	3,861	6,843	9,624
	Kisimbai	1,495	3,095	4,223
	Kulsary	190	415	458
	Koshagyl	226	635	695
	Tyulyus	157	333	371
	Karaton Koshkimbet	360	836	922
	Akkuduk	1,314	2,209	2,459
NGDU KainarMunaiGas				
	Moldabek East	21,269	49,358	59,994
	Zholamanov	3,310	8,074	9,666
	North Kotyrtas	1,904	3,763	4,527
	Uaz	2,347	6,015	8,182
	Kondybai	179	356	549
NGDU DossorMunaiGas				
	Botakhan	7,890	25,363	28,214
	Karsak	2,120	8,051	8,524
	Altykul	1,003	3,082	3,357
	Baichunas	270	917	963
	Bek Bike	212	625	762
	Dossor	17	33	37
	Iskine	8	12	14
	Komsomolskoye	28	57	64
	Koshkar	170	539	570
	Tanatar	175	486	562
	Makat East	8,297	26,393	34,440
	Makat	36	47	53
	Zholdybai North	1,550	4,393	4,798
TOTAL		**600,458**	**1,706,533**	**1,954,569**

Note:

1. Numbers may not add up due to rounding

TABLE 5

LONG TERM OIL PRODUCTION AND EXPENDITURE FORECASTS

		Proved				Proved plus Probable		
		Oil Production t/day	Capex U.S.$MM	Opex U.S.$MM		Oil Production t/day	Capex U.S.$MM	Opex U.S.$MM
2011		24,125	500.6	903.2		24,880	500.6	903.2
2012		24,670	619.2	920.2		25,104	619.2	920.2
2013		24,923	610.2	901.9		25,440	610.2	901.9
2014		24,887	527.6	888.3		25,610	527.6	888.3
2015		24,444	501.6	876.1		25,609	524.6	876.1
2016		23,494	283.2	876.1		25,510	459.6	875.4
2017		22,144	220.4	874.8		25,245	374.7	873.5
2018		19,583	126.2	826.5		24,878	333.9	870.8
2019		16,506	78.4	750.1		24,495	308.9	868.1
2020		13,959	58.9	672.8		24,115	285.3	865.4
2021		4,982	0.2	249.8		23,357	75.5	860.1
2022		0	0.0	0.0		22,165	64.2	851.9
2023		0	0.0	0.0		21,044	54.5	843.9
2024		0	0.0	0.0		19,988	46.4	836.7
2025		0	0.0	0.0		18,987	39.4	829.8
2026		0	0.0	0.0		18,069	33.5	823.6
2027		0	0.0	0.0		17,201	28.5	817.6
2028		0	0.0	0.0		16,379	24.2	811.9
2029		0	0.0	0.0		15,601	20.6	806.6
2030		0	0.0	0.0		14,861	17.5	801.6
2031		0	0.0	0.0		14,299	14.9	797.9
2032		0	0.0	0.0		13,693	12.6	793.5
2033		0	0.0	0.0		13,131	10.7	789.7
2034		0	0.0	0.0		12,604	9.1	786.1
2035		0	0.0	0.0		12,112	7.7	782.8
2036		0	0.0	0.0		11,656	6.5	778.9
2037		0	0.0	0.0		11,229	5.5	775.9
2038		0	0.0	0.0		10,831	4.7	773.2
2039		0	0.0	0.0		10,461	4.0	764.6
2040		0	0.0	0.0		10,107	3.4	762.2
2041		0	0.0	0.0		9,778	2.9	759.7
2042		0	0.0	0.0		9,470	2.4	757.6
2043		0	0.0	0.0		9,182	2.1	755.6
2044		0	0.0	0.0		8,911	1.8	753.8
2045		0	0.0	0.0		8,468	1.4	710.0
2046		0	0.0	0.0		8,240	1.2	708.0
2047		0	0.0	0.0		7,904	1.0	682.0
2048		0	0.0	0.0		7,707	0.8	680.6
2049		0	0.0	0.0		7,520	0.7	679.4
Total		**81,657**	**3,526**	**8,740**		**232,082**	**5,042**	**31,418**

Notes:

1. Proved Reserves are curtailed by Contract Expiry.
2. Numbers may not add up due to rounding.
3. Production totals in Mtonnes; capex and opex totals in U.S.$MM.

the Kulsary area fields at the Proved plus Probable level) and reduced domestic obligation, compared with the 2009 Reserves assessment.

DISCUSSION

Most of the OMG and EMG fields are in a mature stage of development and the Proved and Proved plus Probable Reserves are based mainly on performance history with a reasonable degree of confidence. As in previous evaluations, GCA has generally based its Reserves assessment on an analysis of the development of water cut trends, as well as the field and individual well decline performance. GCA has also included the benefits from new wells and special treatments in both estimating Reserves and production levels. Provision has been made for the future drilling and special treatments programme as presented in the Budget and Business Plans. Estimated Reserves have been checked against stock tank oil initially in place (STOIIP) estimates provided by KMG EP, where available, to ensure that ultimate recovery factors are reasonable and within accepted ranges.

In the Proved scenario the remaining oil is recovered within the term of the licence. In the Proved plus Probable scenario, the production has been taken out to 2049 on the assumption that the contracts will be extended. The Proved and Proved plus Probable forecasts of oil production for the aggregate OMG and EMG fields are summarised in Table 5 above. Both Proved and Proved plus Probable Reserves have been subjected to economic limit testing.

1. FUTURE DRILLING PLANS

The KMG EP proposed drilling plan for 2011 to 2015 is summarised below for EMG and OMG. It excludes any exploration related drilling.

	2011	2012	2013	2014	2015
EMG Producers	57	64	67	63	64
EMG Water Injectors	2	4	4	3	1
OMG Producers	128	144	146	113	115
OMG Water Injectors	52	50	50	50	50

This drilling schedule is considerably more aggressive than in the previous year's plan. For EMG, KMG EP's current schedule for 2011 to 2019 is 403 wells (387 producers), compared with 175 producers in GCA's 2009 Proved plus Probable assessment. For OMG, the 1,211 producers (2011 to 2020) significantly exceed the 880 assumed in GCA's 2009 report.

2. DISCUSSION ON INDIVIDUAL FIELDS

The largest Reserves adjustments (before subtraction of production) at the Proved plus Probable level were for the following fields:

- Nurzhanov (+1,796 Mtonnes);
- Moldabek East (+805 Mtonnes);
- Teren Uzyuk (+603 Mtonnes);
- Uaz (+552 Mtonnes);
- Zhanatalap (+287 Mtonnes);
- Balgimbayev; (+275 Mtonnes);
- North Kotyrtas (+249 Mtonnes);
- Uzen (+229 Mtonnes);
- Kamyshitovoye SE (-108 Mtonnes); and

- Botakhan (-240 Mtonnes).

Reference is made in below to B+C1 estimates of oil in place and ultimate recovery. These relate to the Kazakh system of Reserves classification and are not comparable with the PRMS classification that GCA is following. However, there are fields where GCA considers that the B+C1 values are consistent with the Proved plus Probable (prior to economic limit testing) and GCA uses them as a basis for comparison and in some instances where GCA will accept them in developing long term forecasts for the Proved plus Probable case.

2.1 Nurzhanov

In its 2009 Reserves assessment GCA accepted the B+C1 estimates of oil in place presented in the 2009 Reserves Protocol as a basis for the Proved plus Probable Reserves. This was on the basis of field performance and a review of the reservoir mapping and studies available at the time. GCA also gave consideration to the results of wells that had been drilled to appraise the Triassic reservoirs. However, owing to uncertainties regarding the quality and connectivity of the Triassic and the limited proposed development drilling programme at the time, GCA assigned a reduced recovery factor to the Triassic.

During 2010 there has been further appraisal drilling of the Triassic that has established commercial production from the Triassic in areas of C2 Reserves (i.e. defined as undiscovered). GCA has reviewed the mapping for the Triassic T-IV and has transferred 50% of the C2 area into a Proved plus Probable category. The KMG EP drilling schedule has been increased from 23 wells to 42 wells over the period 2011 to 2016, which GCA considers is necessary to exploit the additional Triassic T-IV oil.

Oil production during 2010 continued to maintain the increasing trend that has been established over the past 11 years, increasing from 755 t/day in 1999 to 1,176 t/day in 2010. GCA understands that there are no production or facilities constraints at Nurzhanov to limit the expected production increases that are expected from the expanded drilling campaign and GCA has removed the limit that was imposed in the 2009 assessment. On the basis of the established production trend, increased drilling commitments and 2010 well results, GCA has increased the Nurzhanov ultimate recovery. A larger proportion of this ultimate recovery is also recoverable during the economic life of the field owing to the unconstrained production potential.

GCA is still reviewing the new data on Nurzhanov, primarily to assess the potential for Triassic Contingent Resources that may not be recovered under the current development plan.

2.2 Moldabek East

GCA recognises the oil in place potential for Moldabek East but has restricted its Reserves estimates in previous assessments on the basis of field performance and the lack of any future development drilling beyond 2010. The field performance during 2010 does not indicate any change in historical trend, but KMG EP has made provision for increased drilling in its Business Plan (85 wells between 2011 and 2019). This increased commitment to drill wells on Moldabek East results in a substantial positive Reserves adjustment at the Proved plus Probable level of 805 Mtonnes.

GCA is reviewing additional studies on Moldabek East to assess the potential for Contingent Resources that may not be recovered under the current development plan.

2.3 Teren Uzyuk

The positive Reserves increase of 603 Mtonnes results from an extension of the economic life of all of the Kulsary area fields, due primarily to higher oil prices.

2.4 Uaz

The pilot production on Uaz ceased in June, 2010. A development plan for full field production has been submitted and provision is made in the KMG EP drilling schedule for 20 additional development wells between 2013 and 2016. GCA has in previous years audited the maps and technical data for Uaz and on the basis of the approved field development plan and drilling programme, has increased the field ultimate recovery by 552 Mtonnes in line with the previously audited B+C1 estimates.

2.5 Zhanatalap

The positive Reserves adjustment of 287 Mtonnes results from the increased drilling commitment and improved 2010 production levels.

2.6 Balgimbayev

The positive Reserves adjustment of 275 Mtonnes results from the increased drilling commitment and improved 2010 production levels.

2.7 North Kotyrtas

A positive Reserves adjustment of 249 Mtonnes has been made on the basis of the increase in the KMG EP drilling programme from 20 to 30 wells over the period 2011 to 2016.

2.8 Uzen

The small positive Reserves adjustment of 229 Mtonnes for Uzen does not fully reflect the increased drilling programme. This is partly because GCA is matching KMG EP's own production forecast to 2020 and because of the ongoing labour disputes and apparent weather related problems in OMG. In recent years, there has been an increasing water cut trend and decreasing oil rate trend that GCA is currently confident can be reversed once the ongoing operational and labour related issues are resolved. OMG field performance will need to be closely monitored during 2011 to ensure that the targets are achievable.

As stated above, GCA has accepted the KMG EP drilling schedule for the Proved plus Probable scenario. The 1,211 producers planned between 2011 and 2020 exceed the 880 assumed in GCA's 2009 report. GCA considers that this drilling programme will be sufficient to maintain the KMG EP long term forecast through until 2020 in the Proved plus Probable scenario.

2.9 Kamyshitovoye SE

A negative Reserves adjustment of 108 Mtonnes has been made on the basis of the reduction in the KMG EP drilling programme from 19 to 5 wells over the period 2011 to 2015.

2.10 Botakhan

The B+C1 ultimate recovery for Botakhan of 5,700 Mtonnes is much lower than GCA's estimate. GCA considered that the field performance in the past was robust enough to support the higher Reserves. During 2010, however, the field performance continued an adverse decline in oil rates and oil cuts that had been established for the previous two years; in addition, the preliminary results of a KMG EP reservoir study indicated that this decline would worsen. On the basis of this study and field performance, GCA has applied a negative Proved plus Probable Reserve adjustment of 240 Mtonnes.

3. ECONOMIC LIMIT TEST

A weighted average price discount to Brent for exported crudes of U.S.$3.93/Bbl was derived based on marketing data and budget plans provided by KMG EP. This discount comprised quality differential and transportation costs. The domestic price is based on price differential information provided by KMG EP, and equates to an average discount of U.S.$56.00/Bbl against Brent.

For the purposes of performing the ELT, the following Brent price scenario was used:

2011 U.S.$95.02/Bbl;
2012 U.S.$94.82/Bbl;
2013 U.S.$94.23/Bbl;
2014 U.S.$94.72/Bbl;
2015 U.S.$97.42/Bbl; and
2016 U.S.$99.37/Bbl.

2017 and beyond escalated at 2.0% pa.

The capex and opex were based on the 2011 budget and 2012 to 2015 business plan. For the purposes of performing the ELT GCA has only included the production related costs, excluding any taxes, royalties, amortisation or transportation costs that are calculated in the GCA cash flow model. These costs are normalised to account for the inflation rate of 2% that the GCA cash flow model is based upon.

The budget and business plan costs have been converted into U.S.$ at an exchange rate of 150 Tg/U.S.$, as per the KMG EP budget and Business Plan.

The long term forecasts of production and expenditures for the Proved and Proved plus Probable scenarios are presented in Table 5 above.

The ELT was performed separately for each of the pre-existing seven NGDUs on the basis that the opex and economic life will generally be dependent on the overall facilities. The basic assumption is that all fields within an NGDU will cease production at the same time.

The economic limits for OMG and the six pre-existing EMG NGDUs are as follows:

	Proved	Proved plus Probable
OzenMunaiGas	2,021	2,049
ZhaikMunaiGas	2,018	2,049
ZhylyoiMunaiGas		
ProrvaMunaiGas	2,020	2,049
KulsaryMunaiGas	2,020	2,046
KainarMunaiGas	2,021	2,044
DossorMunaiGas		
DossorMunaiGas	2,018	2,049
MakatMunaiGas	2,018	2,049

Note:

1. ZhylyoiMunaiGas comprises ProrvaMunaiGas and KulsaryMunaiGas; DossorMunaiGas includes MakatMunaiGas.

At the Proved plus Probable plus Possible level, production is assumed economic for all NGDUs at least to 2049.

The Reserves presented in the above Tables 1 to 4 are based on these economic limits.

4. BASIS OF OPINION

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

It should be understood that any determination of Reserve volumes, particularly involving petroleum developments, may be subject to significant variations over short periods of time as new information becomes available and perceptions change.

Yours faithfully
GAFFNEY, CLINE & ASSOCIATES

Drew Powell
Regional Chief Executive Officer

Appendices

I. Glossary
II. Petroleum Resources Management System Definitions and Guidelines

APPENDIX I

Glossary of Terms

GLOSSARY OF TERMS

List of key abbreviations used in this report.

%	Percentage
Bbl	Barrels
CAPEX	Capital Expenditure
CT	Corporation Tax
E&A	Exploration & Appraisal
EMG	EmbaMunaiGas
EPT	Excess Profits Tax
G&A	General and Administrative costs
GOR	Gas Oil Ratio
IRR	Internal Rate of Return
km	Kilometers
km^2	Square kilometers
KzTg	Kazakh Tenge
m	Metres
m^3	Cubic metres
m^3/day	Cubic metres per day
MKzTg	Thousand Kazakh Tenge
Mm^3	Thousand Cubic metres
Mm^3/day	Thousand Cubic metres per day
MMm^3	Million Cubic metres
M	Thousand
MM	Million
Mtonne	Thousand tonnes
MMtonne	Million tonnes
NGL	Natural Gas Liquids
NPV	Net Present Value
OMG	OzenMunaiGas
OPEX	Operating Expenditure
p.a.	Per annum
PVT	Pressure volume temperature
STOIIP	Stock tank oil initially in place
t/day	Tonnes per Day
U.S.$	United States Dollar

APPENDIX II

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.

<u>RESERVES</u>

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

<u>The development project is currently producing and selling petroleum to market.</u>

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

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

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

<u>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.</u>

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

<u>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</u>

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.

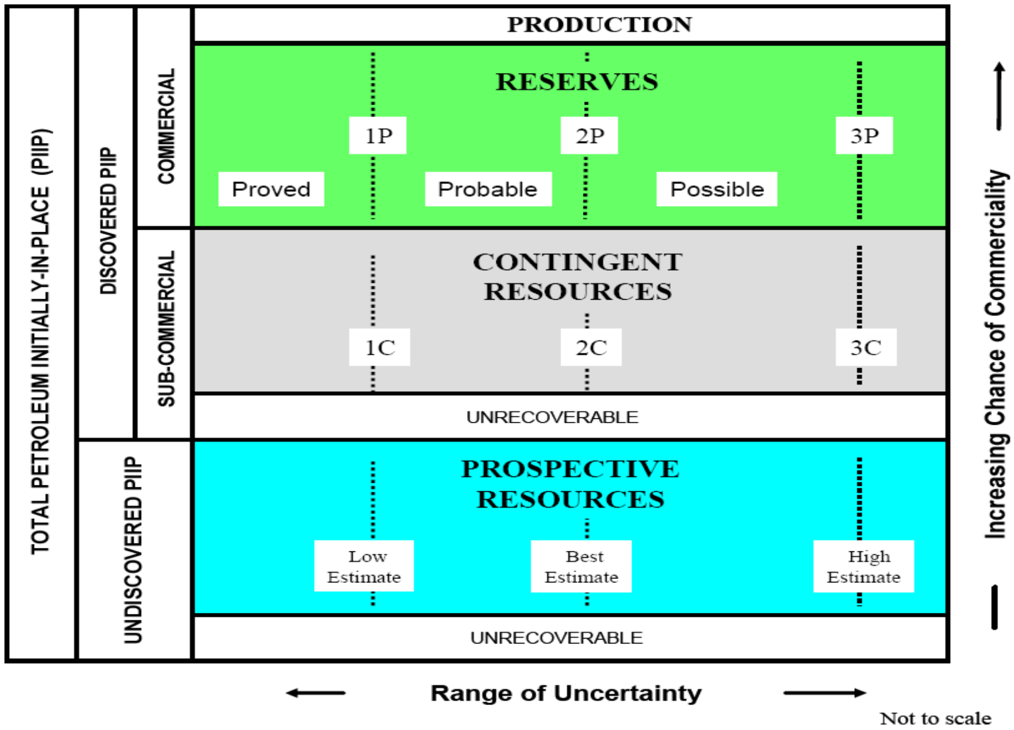
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under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